D.P.U. 94-101/95-36

Petition of Massachusetts Institute of Technology, pursuant to the terms of 220 C.M.R. §§ 8.03(2)(b) and 8.06 and G.L. c. 164, § 93, to establish just and reasonable supplemental, standby, and maintenance rates for services from Cambridge Electric Light Company.

Investigation by the Department of Public Utilities on its own motion as to the propriety of the rates and charges set forth in the following tariffs: M.D.P.U. Nos. 551 through 554, filed with the Department on March 15, 1995, by Cambridge Electric Light Company.

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I. PROCEDURAL HISTORY

On May 11, 1994, Massachusetts Institute of Technology ("MIT") filed a petition with the Department of Public Utilities ("Department") to establish just and reasonable standby, maintenance, and supplemental ("standby/supplemental") rates for services from Cambridge Electric Light Company ("Company" or "Cambridge") required in connection with the operation of MIT's cogeneration facility. On May 25, 1994, Cambridge filed an Answer to MIT's petition pursuant to 220 C.M.R. § 1.04(2). The Attorney General of the Commonwealth ("Attorney General") intervened as of right in this proceeding pursuant to G.L. c. 12, § 11E. This matter was docketed as D.P.U. 94-101.

On December 1, 1994, the Department issued an order wherein the Department determined that it would review the appropriate rate for standby/supplemental service as required by MIT's cogeneration facility. Petition of Massachusetts Institute of Technology, D.P.U. 94-101, Interlocutory Order on Relief, at 5 (December 1, 1994) ("Order on Relief"). Pursuant to the Order on Relief and the Order of Notice also issued on December 1, 1994, the Department conducted a public hearing and procedural conference on December 22, 1994. On January 12, 1995, the Company, MIT, and the Attorney General submitted an interim Settlement Agreement. On February 1, 1995, the Department approved Sections II.D and II.E of the Settlement Agreement, by which the settling parties agreed to an interim rate for standby/supplemental service for MIT and to an adjustment to be made following the establishment of a final rate by the Department. Petition of Massachusetts Institute of Technology, D.P.U. 94-101, Order on Interim Settlement Agreement, at 4 (February 1, 1995).

Pursuant to the procedural schedule, on March 15, 1995, MIT filed the testimony of its witness, Mr. Mark Drazen of Drazen Consulting Group. Mr. Drazen's testimony also included MIT's proposed rate for standby/supplemental service. On the same date, the Company filed with the Department the testimony of Russell Wright, president and chief operating officer of the Company; Henry C. LaMontagne, manager of rate design, COM/Energy Services Company; and Wayne J. Oliver, vice president of Reed Consulting Group. The Company also filed the following four tariffs: (1) Standby Service Rate SB-1 (13.8 kV), M.D.P.U. No. 551; (2) Maintenance Service Rate MS-1 (13.8 kV), M.D.P.U. No. 552; (3) Supplemental Service Rate SS-1 (13.8 kV), M.D.P.U. No. 553; and (4) Customer Transition Charge Rate CTC-1 (13.8 kV), M.D.P.U. No. 554 ("CTC"). The Department docketed the four rate tariffs as D.P.U. 95-36.

By Order dated March 23, 1995, the Department suspended the effective date of the tariffs in D.P.U. 95-36 until October 1, 1995, in order to investigate their propriety. The Department also consolidated the dockets in D.P.U. 95-36 and D.P.U. 94-101. As the petitioner in D.P.U. 94-101, MIT was made a party to the consolidated proceeding. The Attorney General noticed his intervention pursuant to G.L. c. 12, § 11E. In addition, the City of Cambridge ("City") was allowed to intervene as a full party. Boston Edison Company ("BECo"), Eastern Edison Company ("EECo"), Intercontinental Energy Corporation ("IEC"), and Western Massachusetts Electric Company ("WMECo") were granted limited participant status for the purpose of filing a brief.

On May 19, 1995, MIT filed a motion to dismiss the CTC, or, in the alternative, a motion for partial summary judgment rejecting Cambridge's proposed application of the CTC to MIT ("MIT Motions") and a memorandum in support of the motion to dismiss or for partial summary judgment ("MIT Memorandum"). On June 13, 1995, the Company filed an answer to the MIT

Motions ("Company Answer") and a legal memorandum in support of the answer ("Company Memorandum"). On June 14, 1995, the Attorney General filed an objection to the MIT Motions ("Attorney General Objection"). On June 22, 1995, MIT filed a reply to the Company answer and the Attorney General objection ("MIT Reply"). On June 26, 1995, the Company filed a response to MIT's reply ("Company Response").

The Department held evidentiary hearings at its offices on May 30 and 31, and on June 1, 2, and 6, 1995. On June 12, 1995, MIT filed the rebuttal testimony of Mr. Drazen. On July 14, 1995, the Company filed the rebuttal testimony of Mr. LaMontagne and Mr. John J. Reed, president of Reed Consulting Group. The Company also filed an affidavit of Russell Wright. Upon MIT's motion, and over the Company's objection, the Hearing Officer made an oral ruling striking portions of Mr. Reed's testimony which did not serve to rebut Mr. Drazen's testimony, but to supplement the Company's direct testimony (Tr. 6, at 6-8, 112-113). Evidentiary hearings on the rebuttal testimony and affidavit were held on July 24 and 25, 1995.

II. MOTIONS TO DISMISS AND FOR PARTIAL SUMMARY JUDGMENT

A. Positions of the Parties

1. MIT

MIT argues six points in support of the dismissal of the CTC from the rates under review (MIT Motions at 1-2). First, MIT argues that the Department lacks statutory authority under G.L. c. 164, § 94, to approve the CTC because such a fee is not a rate, price, or charge for the sale or distribution of electricity, or for its consumption (MIT Memorandum at 3-6). MIT argues that the statute does not authorize electric companies to file, or the Department to approve, rates and charges in the absence of consumption (id. at 4, 5). MIT asserts that the CTC, which it labels an exit fee, is unrelated to any access to the system (id. at 6).

Second, MIT argues that the proposed CTC is inconsistent with and preempted by the Public Utility Regulatory Policies Act of 1978 ("PURPA")[1] (id. at 6-9). MIT argues that the imposition of a CTC would be in direct conflict with the objectives of PURPA, and would effectively circumvent the policy of promoting alternative energy facilities (id. at 6). MIT argues that the imposition of the CTC on a Qualifying Facility ("QF")[2] violates the requirements of PURPA and the Federal Energy Regulatory Commission ("FERC") regulations in 18 C.F.R. §§ 292.305(b)(1) and 292.305(c) to provide non-discriminatory, cost-based standby and maintenance service if requested by a QF (id. at 7). MIT states that PURPA requires that stand-by rates be just and reasonable (id.). MIT contends that if one were to assume that the Company's proposed stand-by rates were just and reasonable, the imposition of an additional CTC over and above the stand-by service rate must, by definition, be excessive and contrary to the intent of the FERC regulations and PURPA (id. at 8).

Third, MIT argues that the Company has failed to identify any investment or costs which were incurred, prudently or otherwise, to serve MIT or any other large customer, and therefore fails to justify the CTC (id. at 9-10).

Fourth, MIT argues that the Department's regulations do not authorize charging stranded costs to QFs (id. at 10-11). MIT contends that just as the Department cannot take actions outside the scope of its enabling statute, it also cannot establish rates and charges absent a regulation

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1 16 U.S.C. §§ 791a-824r, 2601-2645.

2 Under PURPA, if a power generation project meets certain requirements, it is characterized as a qualifying facility. 16 U.S.C. § 796(18)(B). MIT's power generation project is a QF (see Exhibit A to MIT's Petition in D.P.U. 94-101).

authorizing it to do so (id. at 11). MIT further contends that until such time as the Department establishes guidelines or procedures for charging stranded costs to QFs, if ever, it is premature to allow them to be imposed (id.).

Fifth, MIT argues that the CTC constitutes an improper tying arrangement in violation of antitrust laws (id. at 11-13). MIT alleges that with reference to the CTC, "large customers that install cogeneration facilities and desire to purchase cost-based standby and maintenance service as authorized by PURPA, a bottleneck monopoly product, can only do so if they pay the CTC for unwanted tied full service generation" (id. at 12). MIT alleges that neither MIT nor any other large customer would be allowed to purchase standby/supplemental service, if it failed to pay the CTC (id.). MIT concludes that since the CTC would apply only to those former customers that continue to rely on the Company's transmission and distribution facilities, the CTC is unlawfully tied to the use of such facilities (id. at 13).

Sixth, MIT argues that since MIT has given notice to the Company as required under Rate G-3, prior to the effective date of the proposed CTC, the application of the CTC on MIT is prohibited as retroactive ratemaking (id. at 13-15).

2. Company

The Company claims that none of the six grounds alleged by MIT support summary judgment or dismissal (Company Motion at 1). First, Cambridge contends that the Department does have statutory authority to approve the Company's proposed CTC (Company Memorandum at 5-8). In support, the Company cites the Department's general supervisory authority under G.L. c. 164, § 76, and the long-standing principles underlying the "regulatory compact" (id. at 5). The Company argues that the CTC is not an exit fee, but rather a charge based on the ongoing obligation to serve and the customer's consumption of electricity (id. at 6). The Company explains that under the proposed CTC, the charge is based on the customer's Reference Customer Demand, which reflects the specified maximum Standby Contract Demand that the customer takes from the Company or the average of the most recent 12-month peak demands (id.). The Company claims that the CTC is essentially a "wires charge," in form and substance, and is the same type of charge that is being discussed as necessary to facilitate the movement to a more competitive market pursuant to industry restructuring (id.). According to Cambridge, the CTC is strictly a cost-based mechanism for the Company to recover stranded costs from a customer on whose behalf the Company has previously incurred such costs in order to provide all-requirements electric service (id.). The Company argues that not all charges approved by the Department must be metered on a kilowatthour ("kWh") basis to be properly the subject of the Department's jurisdiction (id. at 7). The Company notes the following examples of charges that are approved by the Department but that are not tied to the consumption of electricity: (1) standard customer charge; (2) rates with ratcheted demand components; and (3) conservation charges (id.).

The Company contends that the proposed CTC is neither inconsistent with nor preempted by PURPA (id. at 8-12). The Company argues that the CTC is independent of the proposed standby/supplemental tariffs and is not intended to recover the direct costs of providing standby/supplemental service (id. at 8). According to the Company, the proposed standby/supplemental service rates are cost-based, non-discriminatory, and just and reasonable and, therefore, are consistent with Congressional intent in enacting PURPA (id. at 8). The Company also contends that the CTC is a just and reasonable charge that is in the public interest (id. at 10). The Company argues that in any event, the propriety of the CTC is a policy and factual matter for the Department to decide based on the record in this case (id.). The Company also argues that the CTC is not discriminatory inasmuch as the charge applies to any customer who is discontinuing all or a portion of all-requirements firm sales service from the Company, regardless of whether the customer is a QF under PURPA or is providing service to its own load without QF status (id. at 11). In support, the Company cites Boston Edison Company, D.P.U. 92-92, at 63 (1992), wherein the Department ruled that because the proposed rate did not single out QFs, the rate was consistent with PURPA (Company Memorandum at 11). The Company contends that the FERC implementing regulations require the Department to implement PURPA rates, so the Department's actions on this matter could not be preempted (id.).

The Company further disputes MIT's argument that the Company has failed to justify any specific investment or expenditures made to serve MIT (id. at 12-13). The Company contends that the CTC is not being offered as a charge that would be applicable only to MIT (id. at 12). The Company states that the costs to be collected pursuant to the CTC have already been reviewed and approved by the Department and have been allocated to the G-3 customer class as part of the approved charges for that rate class (id.). The Company argues that Department ratemaking principles do not require the type of customer-specific cost assignment that MIT implies is necessary (id. at 13). The Company notes that MIT raises issues which go to the factual basis of the case and which should be decided after all facts are decided (id.).

The Company also finds no basis in MIT's claim that the Department is without authority to impose a charge for the collection of stranded costs on a QF since the QF regulations do not expressly provide for such a charge (id. at 13-14). The Company argues that the QF regulations are silent on the issue of stranded costs so the CTC cannot violate them (id. at 13). The Company also contends that the Department's ratemaking authority stems from the General Laws and not from the QF regulations (id. at 14). Again, the Company argues that the CTC is intended to be applicable not just to MIT or other QFs, but to any customer who meets the availability clause in the tariff (id.).

The Company also disputes MIT's claim that the proposed CTC is an improper tying arrangement (id. at 14-18). The Company argues that the case cited by MIT, Cajun Electric Power Co-op, Inc. v. Federal Energy Regulatory Commission, 28 F.3d 173 (D.C. Cir. 1994), did not bar the recovery of stranded costs as claimed by MIT, but found FERC had erred in approving the tariffs without conducting hearings (id. at 15). The Company noted that FERC has since stated that recovery of stranded costs is not a tying arrangement, citing Notice of Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking, 70 FERC ¶ 61,357 (1995) (id. at 15-16). The Company also contends that the Department's regulation in this case is shielded from federal and state antitrust laws under the State Action Doctrine[3] (id. at 16-17).

Finally, the Company argues that the CTC does not represent retroactive ratemaking because the proposed CTC is a new rate that would apply only prospectively upon approval of the Department to recover costs that were prudently incurred to serve the members of the load at risk class (id. at 19-20). The Company alleges that the CTC is no different from long-standing Department ratemaking policy allowing utilities to reflect prospectively in rates costs that have been prudently incurred in the past (id.).

3. Attorney General

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[3] The judicially-created State Action Doctrine was first announced in Parker v. Brown, 317 U.S. 341 (1943), and immunizes certain restraints of trade from antitrust liability. See discussion of the application of the State Action Doctrine in Section VI.B., below.

The Attorney General opposes MIT's motions to dismiss and for partial summary judgment, arguing that MIT cannot meet its burden of establishing that there is no genuine issue of material fact and that MIT is entitled to a judgment as a matter of law since there are many factual disputes in this proceeding (Attorney General Objection). The Attorney General asserts that MIT is not entitled to a judgment as a matter of law on the basis that the Department lacks jurisdiction to establish a CTC (id. at 4). The Attorney General argues that the Supreme Judicial Court has recognized the Department's discretion under G.L. c. 164, § 94 to approve rates that (1) promote the policy of increased competition in the energy market; (2) are not based on the consumption of gas or electricity; or (3) allow a utility to recover prudent investment (id. at 4-5). The Attorney General also contends that MIT's unilateral conclusion that the imposition of a CTC would compromise its ability to purchase back-up power is an area of factual disagreement and therefore, not grounds for dismissal (id. at 6). According to the Attorney General, the Company's proposed CTC does not constitute a tying arrangement (id. at 7-8). The Attorney General asserts that there are factual issues regarding the method that the Company used to calculate the CTC and what costs were incurred and identified (id. at 7). Finally, the Attorney General argues that the proposed CTC would not be prohibited on the basis that it is retroactive ratemaking, because the Department may approve a rate based on the recovery of prudently incurred investment (id. at 10).

B. Standard of Review

The Department's Procedural Rule, 220 C.M.R. § 1.06(6)(e), authorizes a party to move for dismissal or summary judgment as to "all issues or any issue in [a] case" at any time after the filing of an initial pleading. The Department's standard for ruling on a motion to dismiss for failure to state a claim upon which relief can be granted was articulated in Riverside Steam & Electric Company, D.P.U. 88-123, at 26-27 (1988).[4] In D.P.U. 88-123, at 26-27, the Department denied the respondent's motion to dismiss, finding that it did not appear "beyond doubt that the [petitioner] could prove no set of facts in support of its petition."[5] See also Interlocutory Order on Motion to Dismiss of the New England Cable Television Association, Inc., D.P.U. 94-50, at 32 (1995). In determining whether to grant a motion to dismiss, the Department takes the assertions of fact included in the filing and pleadings as true and construes them in favor of the non-moving party. D.P.U. 88-123, at 26-27. Dismissal will be granted by the Department if it appears that the non-moving party would be entitled to no relief under any statement of facts that could be proven in support of its claim. See Id.

The Department has held that summary judgment is proper when there is "no genuine issue of material fact and the moving party is entitled to judgment as a matter of law." Re Altresco Lynn, Inc./Commonwealth Electric Company, D.P.U. 91-142/91-153, at 10 (1991).

C. Analysis and Discussion

For the reasons stated below, the Department has determined that, for each of the six

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4 Procedures for dismissal and summary judgment properly can be applied by an administrative agency where the pleadings and filings conclusively show that the absence of a hearing could not affect the decision. Massachusetts Outdoor Advertising Council v. Outdoor Advertising Board, 9 Mass. App. Ct. 775, 783-786 (1980); Hess and Clark, Division of Rhodia Inc. v. Food and Drug Administration, 495 F.2d 975, 985 (D.C. Cir. 1974).

5 Although D.P.U. 88-123 refers to Massachusetts Rule of Civil Procedure 12(b)(6), the Department has not adopted the Massachusetts Rules of Civil Procedure. These rules, however, sometimes provide useful dispositive models. See e.g., 220 C.M.R. § 1.06(6)(c); see Attorney General v. Department of Public Utilities, 390 Mass. 208, 212-213 (1983) (rules of court do not govern procedure in executive department).

arguments MIT made in support of its Motions, MIT has failed to establish that Cambridge could prove no set of facts to justify the CTC. Therefore, the MIT Motion to Dismiss is denied. As part of the analysis of each of the MIT arguments, the Department also determines whether partial summary judgment is warranted. Where partial summary judgment is denied, the Department examines the issue in Section VI.B., below.

1. Jurisdiction under G.L. c. 164, § 94

MIT argues that the Department lacks jurisdiction under G.L. c. 164, § 94, to approve the CTC because the fee is not a rate, price, or charge for the sale or distribution of electricity, or for its consumption. The Company and the Attorney General argue that the Department does have the authority to approve the CTC.

The Legislature has granted the Department broad ratemaking authority over gas and electric companies. G.L. c. 164, §§ 94, 94G. General Laws c. 164, § 94 describes the Department's statutory obligations to set rates of gas and electric companies:

> Gas and electric companies shall file with the [D]epartment schedules, in such form as the [D]epartment shall from time to time prescribe, showing all rates, prices and charges to be thereafter charged or collected within the commonwealth for the sale and distribution of gas or electricity ....

In addition to the above specific rate-making section, G.L. c. 164, § 76 grants the Department broad supervision of all gas and electric companies:

> The [D]epartment shall have the general supervision of all gas and electric companies and shall make all necessary examination and inquiries and keep itself informed as to the condition of the respective properties owned by such corporations and the manner in which they are conducted with reference to the safety and convenience of the public, and as to their compliance with the provisions of law and the orders, directions and requirements of the [D]epartment ....

These statutory provisions grant the Department wide latitude in the design and setting of rates. See Boston Real Estate Board v. Department of Public Utilities, 334 Mass. 447 (1956). Further, the Supreme Judicial Court has held that the Department's authority to design and set rates pursuant to G.L. c. 164, § 94 is broad and substantial. Massachusetts Oilheat Council v. Department of Public Utilities, 418 Mass. 798, 803 (1994); Boston Real Estate Board v. Department of Public Utilities, 334 Mass. 477 (1956).

MIT argues that the CTC does not relate to the sale or consumption of electricity, while the Company argues that the CTC is connected with the consumption of electricity in the form of standby service. For the purpose of ruling on the Motion to Dismiss, the Department must take the Company's factual assertions contained in its pleadings and filings as true and must construe them in favor of the Company.

However, even if the CTC were not related to the sale or consumption of electricity, the Department would have authority to approve a rate that is not directly based on the sale or consumption of electricity. For example, the Supreme Judicial Court has recognized the Department's authority to approve energy conservation charges which reimburse utilities for the costs of demand-side management ("DSM") activities and are not based upon the consumption of electricity. Monsanto Company v. Department of Public Utilities, 412 Mass. 25, 28 (1992). The conservation charges are based on company expenditures for DSM programs and measured savings from those programs. See, Cambridge Electric Light Company/Commonwealth Electric Company, D.P.U. 95-2/3-CC (1995). These charges recover for the cost of measures that do not result in additional sales but rather in the reduction of future sales. Id. MIT puts too fine a point on the broad statutory language. It is enough that a price or other term be related to electric service for Department justification and authority to attach. The terms of a tariff need not be tied expressly to kWh consumption.

MIT argues that the Department has required that utilities charge ratepayers for the costs of energy conservation programs in rates approved under G.L. c. 164, § 94 based on their current consumption of gas or electricity and not based on the energy saved and no longer consumed, citing Cambridge Electric Light Company and Commonwealth Electric Company, D.P.U. 91-80, Phase Two-A at 144 (1992) (Department ordered the companies not to include a separate line item for the conservation charge rates on customers' bills but to include the conservation charge rates in the energy rates listed) (MIT Memorandum at 3). MIT's argument is misdirected. In D.P.U. 91-80, Phase Two-A at 144, the Department addressed the issue of whether a separate billing listing of the CC appropriately increased ratepayer understanding of the costs and benefits of the conservation and load management programs or was an unfair depiction. The Department determined that it was inappropriate to isolate the costs of a particular resource available to a company. Id. It does not follow that the Department's decision to adopt one method of expressing a charge precludes or implicitly denies its authority to adopt a different, even a contrary, method.

There are numerous other examples of rates approved by the Department which are not based on actual consumption of electricity. These include interruptible rates, customer demand charges, and administrative charges. Therefore, MIT has failed to establish the lack of Department jurisdiction under G.L. c. 164, § 94 to approve the CTC, and thus, MIT has failed to justify its Motion to Dismiss on this ground.

However, the Department finds this issue does not involve a factual question, but rather a legal or statutory interpretation of law and, thus, partial summary judgment is appropriate. As a matter of law and for the reasons stated above, the Department concludes that it has jurisdiction under G.L. c. 164, § 94 to approve a tariff such as the CTC. In Section VI.B., below, the Department determines whether this particular CTC is just and reasonable.

2. PURPA

Congress enacted PURPA in 1978 to encourage the development of alternative power and cogeneration resources by nonutility power generators.[6] Because Congress recognized utilities' reluctance to sell standby/supplemental power to QFs, Congress required that the rates for sale of electricity to QFs be "just and reasonable and in the public interest" and "not discriminate against" QFs. 16 U.S.C. § 824a-3(c); FERC v. Mississippi, 456 U.S. 751, 755 (1982). The FERC regulations implementing PURPA also state that

> Rates for sales which are based on accurate data and consistent systemwide costing principles shall not be considered to discriminate against any qualifying facility to the extent that such rates apply to the utility's other customers with similar load or other cost-related characteristics.

18 C.F.R. § 292.305(a)(2). PURPA was the first important legislative step toward opening and diversifying electric generation, a process that is now being furthered by electric restructuring efforts at the Federal and state levels. Notice of Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking, 70 FERC ¶ 61,357 (1995); Electric Industry Restructuring, D.P.U. 95-30 (1995); Proposed Policy Decision Adopting a Preferred Industry Structure, CA.P.U.C. Case R.94-04-031/I.94-04-032 (1995).

PURPA gives state commissions wide latitude regarding the implementation of the substantive provisions of this act, provided that they do not impose conditions that conflict, or are

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[6] See S. Rep. No. 442, 95th Cong. 1st Sess. 7-10 (1977), reprinted in U.S Code Cong. & Admin. News 7903, 7903-07.

otherwise inconsistent, with PURPA. 16 U.S.C. § 824a-3; See FERC v. Mississippi, 456 U.S. at 751. Therefore, the Department has authority to determine whether the rates for the sale of electricity to QFs are just and reasonable, in the public interest, and non-discriminatory. However, such a determination is factual in nature and cannot be determined as a matter of law. Accordingly, MIT's Motion for Partial Summary Judgment based on this argument is denied. Furthermore, MIT has failed to establish that Cambridge could prove no set of facts to justify the CTC, and thus MIT has failed to justify its Motion to Dismiss on this point. The Department addresses whether the CTC, as applied to MIT, is non-discriminatory, just and reasonable, and in the public interest in Section VI.B., below.

3. Identified Costs

MIT argues that the Company has failed to justify the CTC by identifying any investment or costs which were incurred, prudently or otherwise, to serve MIT or any other large customer. The Company asserts that it has identified the costs to be collected from the CTC customers, i.e., the embedded revenue requirement previously approved by the Department in Cambridge Electric Light Company, D.P.U. 92-250 (1993), with costs allocated to the CTC class as a whole. The Company cites proffered evidence including Exhibits HCL-1, at 27-35, and HCL-13.

If the Department were to take the Company's assertions of fact included in its filing and pleadings as true and were to construe them in the Company's favor, the Company may be able to identify the costs to be collected from the CTC and therefore would have justified its CTC. Thus, the Department finds that MIT's motion to dismiss must be denied on this ground. As events unfolded, the Company's method for calculating the CTC and the costs to be collected thereby did present genuine issues of material fact that required several days of hearings to investigate.

Therefore, MIT's Motion for Partial Summary Judgment on this issue also must be denied. This issue is addressed further in Section VI.B., below.

4. Department Regulations

MIT argues that the Department's QF regulations do not authorize charging stranded costs to QFs. As discussed in Section II.C.1., above, the Department has broad ratemaking authority under G.L. c. 164, § 94, and broad supervisory authority over utilities under G.L. c. 164, § 76. The fact that the Department has not adopted regulations under G.L. c. 30A, § 2, for recovery of stranded costs yet does not restrict the Department's broad statutory authority to promulgate such regulations in the future or to approve charges such as the CTC on a case-by-case basis. Regulatory practice may as readily be shaped by adjudication under G.L. c. 30A, § 10 as by formal rule under G.L. c. 30A, § 2, as the instant proceeding shows. Therefore, MIT has failed to establish that the lack of specific Department regulations on stranded costs precludes the Department from establishing the CTC. Thus MIT has failed to justify its Motion to Dismiss on this point.

However, the Department finds that there is no genuine issue of material fact on this point and thus, as a matter of law, partial summary judgment is appropriate. As a matter of law, the Department concludes that under its general ratemaking and supervisory authority, G.L. c. 164, §§ 76, 94, it may approve a tariff such as the CTC without the prior promulgation of regulations regarding stranded costs.

5. Tying Arrangement

MIT argues that the proposed CTC should be dismissed as it is an improper tying arrangement in violation of antitrust laws.[7] A tying arrangement is "an agreement by a party to

(continued...)

sell one product but only on the condition that the buyer also purchases a different (or tied) product, or at least agrees that he will not purchase that [second] product from any other supplier." Eastman Kodak Company v. Image Technical Services, 504 U.S. 451, at 461 (1992), citing Northern Pacific Railroad Company v. United States, 356 U.S. 1, at 5-6 (1958). A tying arrangement violates antitrust laws "if the seller has `appreciable economic power' in the tying product market and if the arrangement affects a substantial volume of commerce in the tied market." Id., citing Fortner Enterprises, Inc. v. United States Steel Corporation, 394 U.S. 495, 503 (1969). In order to establish a tying arrangement, MIT must prove, first, that standby/supplemental service and the CTC are two distinct products or services and, second, that the Company has used market power in the tying market to force MIT to accept the arrangement, and third, that the arrangement affects a substantial volume of commerce in the tied market. See Jefferson Parish Hospital District No.2 et al. v. Hyde, 466 U.S. 2, 8 (1984). Each part of this test is a genuine issue of material fact, and thus partial summary judgment must be denied. Furthermore, MIT has failed to establish that Cambridge cannot prove a set of facts to demonstrate that the CTC is not a tying arrangement in violation of antitrust laws, and thus MIT's Motion to Dismiss on this point is denied. The Department addresses whether the proposed tariff is an improper tying arrangement and, if so, whether such a restraint of trade is immunized from antitrust liability under the State Action Doctrine in Section VI.B., below.

(...continued)

[7] The Sherman Act, 15 U.S.C. §§ 1, 2, the Clayton Act, 15 U.S.C. §§ 12-27, and the Massachusetts Antitrust Act, G.L. c. 93, §§ 1-14A prohibit a variety of anticompetitive practices of any business engaged in trade. The Massachusetts Antitrust Act, G.L. c. 93, § 1, states that the act should be "construed in harmony with judicial interpretations of comparable federal antitrust statutes insofar as practicable."

6. Retroactive Ratemaking

MIT argues that the imposition of the CTC would be improper under the retroactive ratemaking doctrine and its companion, the filed-rate doctrine (MIT Reply at 8). The filed-rate doctrine generally forbids a regulated entity to charge rates for its services other than those properly on file with the appropriate regulatory authority. Towns of Concord, Norwood & Wellesley v. Federal Energy Regulatory Commission, 955 F.2d 67, at 71 (D.C. Cir. 1992), citing Arkansas Louisiana Gas Company v. Hall, 453 U.S. 571, at 577 (1981) (Stevens J., dissenting). The rule against retroactive ratemaking prohibits the regulatory authority from adjusting current rates to make up for a utility's over- or undercollection in prior periods. Id. at 71, n.2, citing Columbia Gas Transmission Corporation v. Federal Energy Regulatory Commission, 831 F.2d 1135, 1139-1142 (D.C. Cir. 1987). As these ratemaking principles relate to purchasers, their guiding concern is to provide predictability and to allow purchasers to know in advance the consequences of their purchasing decisions. Id. at 75, citing Transwestern Pipeline v. Federal Energy Regulatory Commission, 897 F.2d 570, 577 (D.C. Cir. 1990); Electrical District No. 1 v. Federal Energy Regulatory Commission, 774 F.2d 490, at 493 (D.C. Cir. 1985).[8]

The Company has stated that the CTC is an attempt to collect costs, which the utility prudently incurred in the past to provide service, from a departing customer (Company Brief at 6-7). MIT argues that unless it had notice of the CTC at the time the rate was calculated for the period in which the costs were incurred, MIT could not possibly have predicted the CTC "additional" charge or known the consequences of its purchasing decisions (MIT Reply at 9-10,

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[8] The concern is not unqualified, however. See Commonwealth Electric Company v. Department of Public Utilities, 397 Mass, 361 (1986); Pike County Light & Power v. Pennsylvania, 465 A.2d 735 (1983).

citing Town of Norwood v. Federal Energy Regulatory Commission, 962 F.2d 20, 25 (D.C. Cir. 1992)). MIT further argues that the CTC is essentially a surcharge on the prior rate and, thus, is improper under the retroactive ratemaking doctrine (id. at 10, citing Town of Concord et al., 955 F.2d at 75; Columbia Gas, 831 F.2d at 1140).

In order to determine whether the CTC is in addition to the rate already charged for past electric service, and, therefore, retroactive, the Department must first determine to what the CTC relates. See Associated Gas Distributors v. Federal Energy Regulatory Commission, 898 F.2d 809, at 810 (D.C. Cir. 1990). The Company does not seek to collect from MIT an additional charge for the full-requirement service the Company has provided to MIT in the past. Rather, the Company has proposed a rate designed to recover for investment made in the past to meet its obligation to serve MIT then and into the future -- an investment that must still be recovered by charges for services to others, if not for services to MIT, or by shareholder losses. Clearly, the Department may approve a rate that a utility bases on the recovery of prudently incurred investment. Attorney General v. Department of Public Utilities, 390 Mass. 208, 227 (1983). Moreover, the CTC may be distinguished from the rate at issue in Columbia Gas. In Columbia Gas, 831 F.2d at 1137, the Court of Appeals determined that the rate at issue constituted a surcharge and a retroactive increase in the price of natural gas given that the rate would, in effect, reimburse the pipeline for the amount that the pipeline had subsequently been required to pay to producers for certain deferred production-associated costs. MIT's purchasing decisions would have been unaffected by the proposed CTC as it would apply, not to the customer's consumption as a full-requirements customer, but rather because of MIT's contract demand as a standby customer.

The Department recognized that a stranded charge cost of this type is not retroactive ratemaking in its recent order in Electric Industry Restructuring, D.P.U. 95-30, at 29, 37-39 (1995). There the Department stated that utilities should have a reasonable opportunity to recover, through an appropriately designed mechanism, net, non-mitigatable, stranded costs associated with commitments previously incurred pursuant to their legal obligation to serve. Id.

With regard to the notice issue raised by MIT, the Department notes that even with such notice to terminate service under the G-3 rate, MIT may remain a customer of the Company and would meet the availability criteria of the CTC. As proposed, the CTC will apply to those customers who qualify for the rate only after the Department approves the rate.

The Department finds that there is no genuine issue of material fact on this point and thus, as a matter of law, partial summary judgment is appropriate for this issue. As a matter of law, the Department concludes that the imposition of a tariff such as the CTC does not violate the retroactive ratemaking or filed-rate doctrines. In addition, since MIT has failed to establish that the imposition of the CTC is precluded by the retroactive ratemaking and filed-rate doctrines, MIT also has failed to justify its Motion to Dismiss on this point.

III. THE COMPANY'S PROPOSAL

Cambridge submitted for filing and approval by the Department the following four tariffs:

1. Standby Service Rate SB-1, M.D.P.U. No. 551
2. Maintenance Service Rate MS-1, M.D.P.U. No. 552
3. Supplemental Service Rate SS-1, M.D.P.U. No. 553
4. Customer Transition Charge Rate CTC-1, M.D.P.U. No. 554.

At present, Cambridge does not have standby, maintenance, or supplemental service rates available. The Company stated that until recently no customer has required such services and that if a customer were to request such services, it would have been served under the Company's applicable general service rates (Exh. HCL-1, at 5).

Cambridge proposed that the standby, maintenance, and supplemental service rates be available, upon written application and the execution of an electric service agreement, to customers for whom the Company has an obligation to serve and whose total alternative source of power (1) can be metered by the Company at the interconnection of the alternative source of power and the customer's internal load;[9] (2) exceeds 100 kilowatts ("KW"); and (3) supplies at least 20 percent of the customer's total integrated electrical load (id. at 5; Exhs. HCL-2; HCL-3; HCL-4).

IV. MIT'S PROPOSAL

Originally, MIT proposed that rates for standby service be developed in a manner consistent with other rates, i.e., by using an allocated cost of service approach (Exh. MIT-176, at 12). MIT indicated that, first, there should be an allocated test-year embedded cost based on MIT's standby load and that, second, rates should be designed based on marginal cost and adjusted to produce the annual revenue requirement (id.). According to MIT, the embedded cost of service for standby service should be calculated by taking the costs allocated to a class with the same voltage level characteristics and modifying it to reflect the load pattern of standby and maintenance service (id. at 13). MIT determined that costs should be allocated based on the

9 According to Cambridge, if the alternative source of power were not metered, the Company would have no way of independently determining the actual level of power the customer received from its alternative source, and therefore, would have no way of determining the level of standby, maintenance, and or supplemental service received from the Company (Exh. HCL-1, at 6).

expected average standby service load, which is equal to MIT's cogeneration unit output times a five percent forced outage rate ("FOR") spread equally over all hours (id.). MIT stated that an appropriate rate for standby service should comprise the following elements: (1) a generation and transmission ("G&T") minimum annual charge; (2) a G&T daily demand charge; (3) a distribution demand charge; and (4) an energy charge (id. at 16).

With regard to maintenance service, MIT submitted that because maintenance service can be scheduled during off-peak times, thus avoiding capacity-related costs, such service should only be billed at the Company's short-run energy purchase rate for qualifying small power production and cogeneration facilities ("Rate P-1") (id. at 16).[10] With regard to supplemental service, MIT proposed that the rate be set at the applicable general service rate, which is Rate G-3 (id. at 25-26).

While its original proposal regarding the appropriate manner in which to design rates for supplemental service remained consistent throughout the proceeding, MIT revised its proposal with respect to the appropriate manner in which to design rates for standby service and the appropriate charges to include in the rate for maintenance service (Exh. MIT-182). MIT's position is described in Sections V.A.2.a. and V.B.1.a., below.

V. STANDBY, MAINTENANCE, AND SUPPLEMENTAL TARIFFS

The Company stated that its objectives in establishing the proposed rates were to design rates that (1) recover the cost of the service provided, (2) send proper price signals, and (3) are reasonable (Exh. MIT-182). According to Cambridge, these rates will facilitate the transition to a

[10] On brief, MIT argues against the level of costs in the Company's local transmission and distribution charge, but not the proposed inclusion of such a charge as part of the Maintenance Service Rate (MIT Brief at 14).

more competitive market and be responsive to customer choices in that market (id. at 9).

A. Standby Service Rate SB-1

The Company stated that it has no cost or load data specific to standby service, therefore, in structuring the proposed Standby Service Rate, the Company did not determine an embedded cost revenue requirement for the standby service rate class (id. at 12-13). Instead, Cambridge set the component charges of the rate equal to the Company's marginal costs (id.). The Company stated that standby service is intended to provide customers with a back-up supply of power when a customer's alternative source of power is either partially or totally unavailable (id. at 4). The Company's proposed Standby Service Rate is a marginal-cost-based rate and is designed to have an administrative charge, a customer charge, a local transmission and distribution ("T&D") capacity charge, a generation and off-system transmission ("G&OT") capacity charge and a G&OT capacity reservation charge (id. at 10). The following is a description of these charges.

1. Description of the Company's Charges

a. Administrative Charge

Cambridge proposed that an administrative charge of $300 per month be applied to its Standby Service Rate (id. at 14). The Company indicated that the administrative charge is designed to recover the additional costs incurred by Cambridge in the administration of a customer's account on the Standby Service Rate which are not captured in the Company's marginal customer costs (id.). The Company proposed that one administrative charge be assessed to a customer who takes any or all three of these services (standby, maintenance, or supplemental service) (id. at 15).

b. Customer Charge

The Company proposed a customer charge of $567 per month for its Standby Service Rate (Exh. HCL-2). According to Cambridge, the monthly customer charge is equal to the marginal customer costs approved by the Department in the Company's last rate case, Cambridge Electric Light Company, D.P.U. 92-250 (1993). The Company proposed that one customer charge be assessed to a customer who takes any one or all three of these services (standby, maintenance, or supplemental service) (Exh. HCL-1, at 15).

c. Local T&D Capacity Charge

Cambridge proposed a local T&D charge of $4.01 per kilovoltampere ("kVa") (Exh. HCL-2). The Company stated that it set the local T&D charge equal to the marginal local T&D costs approved in D.P.U. 92-250 (Exh. HCL-1 at 15). Cambridge proposed to assess this charge on each kVa for which the customer requests standby service ("Standby Contract Demand") from the Company (id.). The Company indicated that it is appropriate to assess a local T&D charge on this basis because the level of local T&D investment necessary to serve a customer requesting standby service is fixed and does not vary with the intermittence of the customer's actual load (id. at 16). Further, according to Cambridge, the investment in local T&D cannot be used to serve another customer when a standby service customer is not receiving electricity from the Company (id.).

d. G&OT Capacity Charge

The Company proposed a G&OT capacity charge of $7.13 per kVa (Exh. HCL-2). Cambridge proposed to assess the monthly per kVa G&OT charge on the maximum 15-minute actual replacement demands established by the customer during the Company's peak period of the billing month (Exh. HCL-1, at 16). According to Cambridge, its proposed G&OT charge is also based on the marginal cost study approved by the Department in D.P.U. 92-250, and is set equal to the Department-approved marginal G&OT costs (id.). The Company stated that assessing demand-related charges on a monthly basis is a standard ratemaking practice and is consistent with Department precedent for both regular service and standby service rates (id. at 17).

e. G&OT Capacity Reservation Charge

Cambridge proposed a G&OT capacity reservation charge of $1.31 per kVa (Exhs. HCL-14, at 14; HCL-15). This monthly per kVa charge is assessed on each kVa of Standby Contract Demand.[11] The Company stated that the purpose of the G&OT capacity reservation charge is to compensate Cambridge for standing ready at all times to serve the customer's full standby contract demand (Exh. HCL-1, at 18). The Company derived the G&OT capacity reservation charge by multiplying the monthly G&OT capacity charge by 21.62 percent, the Company's average forecasted New England Power Pool ("NEPOOL") reserve margin requirement over the next five years (id. at 18). According to Cambridge, the purpose of the NEPOOL reserve margin is to ensure that the Company will have sufficient capacity to meet the needs of its customers (id. at 20). Therefore, the Company stated that because Cambridge will satisfy the standby service load requirements with generation capacity from its reserve margin, it is appropriate to use the NEPOOL reserve margin to calculate the Company's proposed reservation charge for G&OT costs (id.).

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[11] Under the Company's proposal, the total charges for G&OT capacity in each month shall be the greater of the monthly G&OT capacity reservation charge, or the monthly G&OT capacity charge (Exh. HCL-2).

f. Energy Charge

The Company proposed that the energy charge for the Standby Service Rate be set equal to the energy purchase rates at the appropriate voltage level contained in Rate P-1 less the applicable fuel charge under the otherwise applicable rate schedule (id. at 22). Cambridge stated that the Company's Rate P-1 is a reasonable proxy for the Company's marginal energy costs (id. at 23). The Company proposed that standby energy be subject to the conservation charge and the fuel charge that may be applicable under the rate schedule for which the standby service customer would qualify if the customer did not own and operate generating facilities (id. at 22).

2. Positions of the Parties

a. MIT

MIT criticizes six aspects of the Company's proposed Standby Service Rate: (1) the administrative charge; (2) the use of the NEPOOL reserve margin percentage for setting the G&OT reservation charge; (3) the lack of prorating in the G&OT demand usage charge; (4) the 100 percent contract demand ratchet for distribution; (5) the treatment of half of local T&D costs as related to non-coincident peak; and (6) the use of marginal costs for setting the charges (Exh. MIT-182, at 4; MIT Brief at 22-33; MIT Reply Brief at 30). According to MIT, these flaws in the design of the rate cause the resulting costs to be higher than a standby customer would pay under general service Rate G-3 (Exh. MIT-182, at 4; MIT Brief at 22-33; MIT Reply Brief at 30). Finally, with respect to the Company's filing, in general, MIT asserts that Cambridge has not negotiated in good faith (Exh. MIT-182, at 31).

First, MIT argues that Cambridge's proposed administrative charge of $300 per month is not cost-justified (MIT Brief at 21). MIT maintains that although the Company did provide a cost study, the assumption that standby, maintenance and supplemental service requires 500 hours of programming is unreasonable, especially in light of the fact that no such charge was applied to Harvard University in its contract with Cambridge, which required multiple meters, or in the Company's experimental rates (RR-DPU-2; MIT Brief at 22).

Second, MIT states that using a reserve margin percentage to establish a reservation charge makes sense only if there is no additional usage charge for actual outages (Exh. MIT-182, at 6). According to MIT, the reservation charge should be based on an FOR of five percent, and the costs associated with any additional outages should be recovered in the demand charge for actual outages (the daily demand charge) (id. at 7). According to MIT, setting the annual minimum at a level higher than a reasonable expectation of the cogenerator's FOR penalizes good performance (id. at 8). In addition, MIT claims that an annual reservation charge ignores the differences between peak and off-peak months (MIT Reply Brief at 29).

Third, MIT claims that an outage of any duration should not result in a full month's demand charge; it should be prorated based on the actual duration of use (Exh. MIT-182, at 13-14). MIT points out that both EECo and WMECo have standby rates in effect that use daily demand charges and so does the contract between Commonwealth Electric Company ("Commonwealth") and Dartmouth Power Associates Limited Partnership ("Dartmouth Power") (id. at 11; MIT Brief at 24-25; MIT Reply Brief at 27, citing RR-MIT-15). MIT also argues that lack of proration can provide a customer with an incentive to use more backup power (Exh. MIT-182, at 12-13; MIT Brief at 26).

Fourth, MIT claims that the Department has a long standing policy against demand ratchets (Exh. MIT-182, at 15). According to MIT, the effect of a demand ratchet is that the amount of distribution charge that MIT would pay as a standby service customer is higher than the distribution charge (embedded in the Rate G-3 demand charge) that MIT pays as a full requirements customer (id.). MIT asserts that although EECo and BECo have demand ratchets in place, EECo uses a daily proration charge and there is no reservation charge, and BECo's demand ratchet is based on a fraction of distribution costs (id. at 16; MIT Brief at 23). In addition, MIT states that the contract between Commonwealth and Dartmouth Power calls for a distribution charge based on actual monthly demand (MIT Reply Brief at 26-27, citing RR-MIT-15).

Fifth, MIT maintains that the Company's proposed local T&D charge, which includes a portion of transmission costs and all bulk distribution costs, is designed inappropriately, because it implies that all bulk distribution costs and about half of transmission costs are caused by a customer's non-coincident peak ("NCP") demand (Exh. MIT-182, at 16-17). According to MIT, such treatment of these costs in the present case is inconsistent with the Company's position in D.P.U. 92-250 (id. at 17-18; MIT Brief at 29). MIT notes that in the present case, Cambridge claims that the level of local T&D investment necessary to serve a standby customer does not vary with the intermittence of the customer's actual load, so that the Company must make certain investments to serve that customer's maximum requested backup demand regardless of the actual need level (Exh. MIT-182, at 17, citing Exh. HCL-1, at 16). In contrast, MIT points out that in D.P.U. 92-250, the Company promoted the use of the proportional responsibility ("PR") method rather than the NCP method to allocate transmission and bulk distribution costs (Exh. MIT-182, at 17). MIT asserts that in D.P.U. 92-250, the Company stated that it was appropriate to allocate the cost of transmission and bulk distribution substation facilities to costing periods, which reflect the time-varying level of aggregate company loads (Exh. MIT-182, at 17, citing D.P.U. 92-250

Testimony, Volume 3, Tab J at 13). MIT claims that Cambridge has not shown that its system is materially different now than it was in D.P.U. 92-250 (id. at 18). According to MIT, there is a significant difference between the allocation of costs based on a PR versus an NCP method to such an extent that the NCP method results in allocated costs nine times higher as the PR method (MIT Brief at 32). Therefore, MIT argues that, following the Company's logic in D.P.U. 92-250 and MIT's proposed rates, the Department should approve a distribution demand charge based on the cost of 13.8 kV lines only, and that all transmission costs and 13.8 kV substation costs should be included with the generation costs in the annual reservation and daily demand charge (Exh. MIT-182, at 19).

Finally, MIT argues that the Department has never set rates based solely on marginal costs; they are always constrained by an overall embedded cost requirement (id. at 19). MIT points out that between the Company's last two rate cases, D.P.U. 92-250 and D.P.U. 89-109 (1989), marginal costs fluctuated significantly, so that the use of marginal costs to develop a standby rate is not reliable (id. at 19-20).

MIT disagrees with the Company's contention that if a standby customer has outages in all twelve months, Rate G-3 would be more expensive than the proposed standby rate (id. at 5). According to MIT, the Company's comparison of Rate G-3 to the proposed Standby Service Rate contains several factual errors (id., citing Exh. HCL-8). First, MIT maintains that the demand assumed for Rate G-3 (i.e., 2,000 kVa) would be lower than under the proposed Standby Service Rate, because Rate G-3 has no demand ratchet (id. at 5). MIT asserts that a customer with a maximum monthly demand of 2,000 kVa would probably have lower demands in most other months (id.). In fact, MIT states that its total annual billing demand is approximately ten percent lower than twelve times the maximum monthly demand (id.). Second, MIT points out that the Company's calculation includes a demand charge of $11.50 for Rate G-3, even though the charge for the first 100 kVa is $624.66 (id.). Third, MIT criticizes the Company's assumed energy charge for standby service of 2.4 cents per kWh, because the current Rate P-1 is 2.7 cents per kWh (id.). Finally, MIT maintains that the calculation includes a $300 per month administrative charge in Rate G-3, even though no such charge exists (id.). Therefore, MIT concludes that the customer who experiences twelve monthly outages will pay more under the proposed standby rate than under Rate G-3 (id.).

According to MIT, Cambridge did not negotiate in good faith in two specific respects (id. at 31-33). First, MIT asserts that, between 1992 and 1995, the Company changed its position regarding the existence of a "buy/sell" agreement between MIT and Cambridge from one of support to a lack of consideration (id.). Second, MIT claims the Company's position regarding the reservation charge and prorated usage charges in this case is opposite to that during negotiations (id. at 32-33).

As an alternative to its original position that the standby rate be based on the revenue requirement for Rate G-3 that was determined in D.P.U. 92-250, MIT recommends calculating a standby rate based on a disaggregated Rate G-3 (Exhs. MIT-176; MIT-182). According to MIT, this approach both treats full requirements and standby customers consistently, and avoids the problems that can be caused by variability in marginal cost results (Exh. MIT-182, at 30-31).

In MIT's view, the purpose of a standby rate is to provide service to a partial requirements customer, when that customer's generation is out of service due to forced outages (MIT Brief at 15). MIT contends that PURPA requires that standby rates reflect the load and operating characteristics of QFs and that there is no reason to assume that a QF's forced outage will occur during a utility's peak period (id. at 16). MIT maintains that the standby rate should be designed by disaggregating Rate G-3 (id.; Exh. MIT-182, at 25, 30-31). MIT points out that the result of this approach differs only slightly from developing that rate on the cost of service for Rate G-3, because the embedded unit costs for Rate G-3 are based on the average load characteristics for that class versus the expected load characteristics of standby usage (MIT Brief at 17). MIT contends that the appropriate rate should have the following components: (1) a customer charge; (2) a G&T charge; (3) a distribution charge; and (4) an energy charge (id. at 17-19). The following is a description of these charges.

i. Customer Charge

MIT submits that the customer charge for the standby rate should be the same as that for Rate G-3, or $100 per month, as opposed to the Company's proposed customer charge of $567 per month (id. at 17, 21).[12]

ii. G&T Charge

MIT recommends a G&T charge of $0.93 per kVa per day during the peak months and $0.20 per kVa per day during the off-peak months, subject to an annual minimum charge of $5.61 per kVa (Exh. MIT-182, at 27; MIT Brief at 18). The annual cost of G&T capacity of $112.20 per kVa per year is the sum of disaggregated G-3 production transmission and bulk distribution substation costs multiplied by 12 months (Exh. MIT-182, at 27; MIT Brief at 18). This was then divided by the number of 260 peak days per year to arrive at an average daily demand cost of

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[12] MIT points out that the Company submitted an alternative standby service rate based on a disaggregated Rate G-3 in which the customer charge was set at $100 per month (Exh. HCL-14, at 24; MIT Brief at 21, n.6).

$0.44 (Exh. MIT-182, at 27; MIT Brief at 18). This cost was multiplied by factors reflecting different capacity costs during peak months (2.1 times the average daily demand cost) and off-peak months (.45 times the average daily demand cost) (Exh. MIT-182, at 27; MIT Brief at 18). MIT indicates that the annual minimum reservation charge is the annual cost of capacity multiplied by the expected FOR of five percent (Exh. MIT-182, at 27; MIT Brief at 18). MIT contends that while the annual reservation charge reflects the expected average cost of serving standby load, the daily demand charge ensures that if the customer requires service more frequently than the assumed FOR, the customer will pay for that additional usage (Exh. MIT-182, at 7; MIT Brief at 18).

iii. Distribution Charge

According to MIT, the monthly distribution charge of $1.84 per kVa is based on the cost of distribution lines embedded in the G-3 demand charge, which is equal to 62 percent of the total distribution costs (Exh. MIT-182, at 26; MIT Brief at 19). This charge is assessed on the customer's monthly maximum demand (Exh MIT-182, at 28).

iv. Energy Charge

MIT recommends energy charges equal to Cambridge's Rate P-1 that is in effect at the time of MIT's energy usage (See Exh. MIT-176, at 24).

v. Distribution Facilities Credit

In its reply brief, MIT argues that it should receive a $1.4 million credit to the standby service rate to recognize its payment toward incremental distribution facilities pursuant to an Interconnection Agreement between MIT and the Company (MIT Reply Brief at 33-34, citing MIT Petition, D.P.U. 94-101). According to MIT, failure by the Company to provide a credit would require MIT to pay both marginal costs and incremental costs for the same distribution facilities, and would be in violation of the "just and reasonable" standard for standby service pricing under PURPA (id. at 34, citing 16 U.S.C. § 824a-3(C)). MIT asserts that FERC rejected an attempt to charge a customer twice for the same transmission facilities (id., citing Pennsylvania Electric Company, 58 FERC ¶ 61,278, reh'g denied 60 FERC ¶ 61,034 (1992), aff'd Pennsylvania Electric Company v. FERC, 11 F.3d 207 (D.C. Cir. 1993)).

b. The Company

i. Administrative Charge

The Company argues that its proposed administrative charge is supported by the record (Company Reply Brief at 48-49, citing RR-DPU-2). The Company contends that this charge is appropriate because it reflects the additional metering, analysis, and Company resources needed to identify specific levels of standby, maintenance and supplemental services associated with backup rates (id.).

ii. Customer Charge

The Company opposes MIT's suggestion that the customer charge be set at $100 per month, identical to the customer charge now in effect for Rate G-3 (id. at 49). The Company asserts that because of rate continuity considerations, the Rate G-3 customer charge could not be set at full marginal cost (id.). Cambridge maintains that in this case, the Company is not constrained by continuity considerations, and there is no existing class of standby customers (id. at 50). The Company argues that it is appropriate to assess the full marginal customer cost because it will send the most economically efficient price signal to customers (id.).

iii. Local T&D Capacity Charge

Regarding MIT's argument that the Department has a long-standing policy against demand ratchets, the Company contends that such policy as it relates to standby rates has evolved and that the Department has recently approved annual distribution contract demand charges in proposed standby rates for EECo and BECo (Exh. HCL-14, at 17, citing Eastern Edison Company, D.P.U. 92-148, at 36-37 (1992); Boston Edison Company, D.P.U. 92-92, at 58-63 (1992).

With respect to MIT's argument that Cambridge's proposed local T&D charge would recover more than the distribution portion of the Rate G-3 demand charge because the charge is applied to a customer's contracted demand instead of actual demand in each month, the Company contends that MIT's estimate of a ten percent differential in billing demands under the Company's proposal is overstated, and that instead, the difference in billing demands would be only 3.7 percent of the actual billing demands (Exh. HCL-14, at 18-19).

Regarding MIT's criticisms with respect to the categories of cost that should be recovered through the local T&D capacity charge, the Company argues that such criticisms are misplaced and unfounded (id. at 19). Cambridge contends that the testimony cited by MIT deals with issues related to the allocation of certain embedded costs among customer classes and not with issues related to intraclass rate design (id.). The Company argues that although Cambridge allocated 13.8 kV T&D facilities on a PR basis in D.P.U. 92-250, that allocation was for a customer class with a different load that was continuous and not representative of the characteristics of standby service (Company Brief at 113). Therefore, Cambridge reasons that it is inappropriate to compare the cost allocation methodology used by the Company for full service Rate G-3 customers which have relatively continuous load patterns, to the cost allocation methodology used for standby service (id.).

The Company maintains that for the standby service load patterns and capacity levels requested by MIT, Cambridge's T&D planners consider the maximum demand to be served as the most important cost causative factor with respect to the Company's local T&D marginal costs, and that MIT has provided no evidence to the contrary (Exh. HCL-14, at 19). Therefore, Cambridge asserts that its proposal to include local transmission and all distribution-related costs in the local T&D capacity charge is appropriate (id.).

iv. G&OT Capacity Charge

The Company argues that its proposed G&OT capacity charge should not be prorated on a daily or hourly basis, because the costs associated with G&OT investments and commitments are not incurred on a daily or an hourly basis (Exh. HCL-14, at 7-8). The Company contends that contrary to MIT's position, cost responsibility does not follow a probabilistic assessment of usage; rather, cost responsibility is most appropriately matched with cost incurrence (id. at 9). Cambridge asserts that if capacity costs are prorated on a daily basis and standby loads are established based on FOR expectations, the Company will not recover from standby customers the cost of capacity that is required to serve that load (id. at 8-9; Company Brief at 101-104).

v. G&OT Capacity Reservation Charge

The Company argues that a reservation charge based upon the FOR of a customer's self-generation unit would not adequately compensate the utility for providing standby service, because it does not reflect how a utility incurs costs to serve standby load (Exh. HCL-14, at 14). According to Cambridge, this is because the Company's reserve margin, and not the self-generating unit's expected FOR, which reflects the required level of replacement capacity that the Company must have available in order to serve a standby load in the event of a forced outage

(Company Brief at 108). Cambridge maintains that the implementation of an FOR-based reservation charge would result in other customer classes subsidizing the standby service class because that class would not be contributing its fair share to the recovery of G&OT capacity costs or the required reserve capacity (Exh. HCL-14, at 14).

Cambridge contends that MIT's argument that using a reserve margin percentage to establish a reservation charge would be appropriate only if there is no additional charge for actual outages is illogical (id. at 15). The Company argues that the full cost of providing standby service is a function of both the cost associated with the amount of load that a utility must plan for and the capacity actually used by the standby customer (id.). According to Cambridge, the reserve margin percentage times the Standby Contract Demand is the amount of load that a utility must plan for, and the associated costs must be recovered from the standby customer. In the event that the customer's actual use exceeds the reserve margin amount, then additional costs are incurred to serve that load (id. at 15-16). Therefore, the Company maintains that it is appropriate to charge standby customers the greater of the reservation charge (G&OT capacity reservation charge) or a usage charge (G&OT capacity charge) (id. at 16; Company Brief at 104-105).

Addressing MIT's argument that setting an annual minimum reservation charge at a level higher than the expected FOR would result in penalizing a self-generator's good performance, the Company asserts that the purpose of the reservation charge is neither to reward nor penalize a self-generator for its performance, but rather it is intended to recover the costs associated with the Company standing ready at all times to serve the customer's full standby contract demand whenever the customer requires standby service (Exh. HCL-14, at 16).

vi. Use of Marginal Costs

Cambridge asserts that the marginal costs relied upon by the Company to develop its proposed standby rate were the subject of detailed Department review and were approved by the Department in D.P.U. 92-250 (Company Brief at 118). The Company argues that MIT's position that the Department has never set rates based solely on marginal costs is incorrect (Exh. HCL-14, at 20). Cambridge contends that the Department has used marginal costs as an important factor in establishing rates for a number of electric, gas and telephone companies (id.). The Company argues that the use of marginal costs to set the charges for the proposed standby service in this case is appropriate for two reasons. First, marginal costs send the proper price signal to customers and promote economic efficiency (id. at 21). Second, standby service is a new service for the Company and as a result it does not have an established revenue requirement on which to base its standby service rate (id.).

vii. Alternative Rate

The Company states that if the Department were to determine that another method is preferable to the Company's marginal cost-based standby rate, Cambridge would support an alternative standby rate based on a disaggregation of Rate G-3 as presented by the Company in Exhibit HCL-17 (id. at 23; Company Brief at 122).[13]

The Company takes issue with MIT's proposed disaggregated Rate G-3, because it relies

[13] The Company developed the disaggregated rate by disaggregating its existing two-tier Rate G-3 demand charge of $624.66 for the first 100 kVa and $11.50 per kVa over 100 kVa into separate two-tier demand components for: (1) the local monthly T&D capacity charge ($2.25 per kVa for the first 100 kVa and $4.14 per kVa over 100 kVa); (2) the monthly G&OT demand charge ($4.00 per kVa for the first 100 kVa and $7.36 per kVa over 100 kVa); and (3) the G&OT reservation charge ($0.73 per kVa/month for the first 100 kVa and $1.35 per kVa/month for kVa over 100 kVa). The disaggregated rate also includes an administrative charge of $300.00 per month, and a customer charge of $100.00 per month (Exh. HCL-14, at 24-25).

on a weighted average Rate G-3 demand charge (Company Brief at 122-123). Cambridge contends that MIT's method of disaggregating Rate G-3 is flawed because an average demand charge would result in over-recovery from smaller customers and under-recovery from larger customers (id.).

viii. PURPA Requirements

The Company asserts that its proposed standby tariff is fully consistent with the requirements of PURPA that the rate be cost-based, non-discriminatory, and just and reasonable (Company Brief at 92-93). Cambridge agrees with MIT that PURPA specifies that the need for standby service should not be assumed to occur at the same time as the system peak demand (id. at 94). However, the Company argues that contrary to MIT's contention, Cambridge's proposed standby rate is not based on the assumption that the forced outages of standby customers will occur simultaneously or during the system peak (id.). The Company maintains that as to the method of pricing, Cambridge is not treating standby load any differently from the manner in which the Company treats a typical all-requirements Rate G-3 customer's demand (id.). Therefore, the Company asserts that Cambridge is neither discriminating against nor in favor of QFs in its proposed rate design, which in turn is consistent with the requirements of PURPA.

ix. The Company's Proposed Rates Versus Rate G-3

The Company argues that MIT's claim that Cambridge's proposed standby rate taken together with the CTC is higher than continuing service on the Company's existing Rate G-3 is erroneous because it is based upon a faulty assumption (Company Brief at 126). The Company contends that MIT wrongly assumes that a customer with self-generation would build a generating facility that did not maximize its load factor (id.). Cambridge maintains that in reality, customers who choose to self-generate will maximize their investment return by attempting to run their facility at as close to 100 percent load factor as possible, and as a result, there is likely to be little disparity between the total annual billing demand for standby service and the total annual billing demand for Rate G-3 (id. at 126-127). The Company contends that a comparison of its standby service rate with Rate G-3 indicates that Rate G-3 is more expensive (Exh. HCL-14, at 27).

The Company also argues that it is inappropriate to compare the Rate G-3 demand charge with the sum of the standby service demand charges and the CTC demand charge, because although the standby and CTC charges reflect the full value of demand-related costs, a substantial amount of embedded demand-related costs are recovered through the Rate G-3 energy charge and are not reflected in the Rate G-3 demand charge (id. at 28).

x. Actions During Negotiations

The Company contends that it has acted prudently and reasonably in its dealings with MIT (Company Brief at 55). Cambridge asserts that from the time MIT first communicated its intention to pursue self-generation, the Company took many steps to retain MIT as a full-requirements customer by negotiating with MIT in order to avoid adverse rate impacts and produce benefits for MIT (id. at 50-54). Further, the Company contends that MIT's allegations that the Company has not acted in good faith in all dealings with MIT are unfounded and contradicted by record evidence (id. at 55-58). Finally, the Company asserts that MIT's references to prior agreements regarding standby service are "off the mark" and irrelevant (id. at 90-92).

c. The Attorney General

The Attorney General posits that the Company's proposed standby, maintenance and supplemental service rates[14] are within the ambit of Department policies on partial requirements service and should be approved (Attorney General Initial Brief at 4). The Attorney General argues that the Department's precedent on partial requirements service requires that such rates "unburden the Company's full requirements customers from subsidizing the cost of dedicated facilities that are used intermittently" (id., citing D.P.U. 92-92). The Attorney General also argues that the Department should reject MIT's proposal that its partial requirements service be rendered on the basis of a disaggregated G-3 rate since such proposal is based on arguments concerning positions taken and ideas explored during negotiations, which occurred before this proceeding and which are irrelevant and of no evidentiary value (id. at 14).

The Attorney General addresses five criticisms advanced by MIT of the standby rate (id. at 11-13). First, with reference to MIT's argument regarding the use of the NEPOOL reserve margin percentage for setting the G&T reservation charge, the Attorney General contends that because MIT's presence on the Company's system will affect the Company's reserve margin requirements, it is appropriate to employ forecasted NEPOOL average reserve margin requirements as the cost basis for the reservation charge (id. at 12, citing Exh. HCL-14, at 16). Second, the Attorney General argues that since utility G&OT investments and commitments can rarely be made on a daily or hourly basis, the proposed rate should be approved as it provides the best means to match responsibility and recovery (id.). With reference to MIT's criticism of the

[14] The Attorney General notes that since MIT has not raised any objection to the proposed Supplemental Service Rate and its objections to the Maintenance Service Rate are similar to its objections to the Standby Service Rate, the Attorney General only addresses issues regarding the proposed Standby Service Rate (Attorney General Initial Brief at 10).

proposed demand ratchet as contrary to Department policy, the Attorney General argues that the Department has previously approved standby rates that have included annual distribution contract demand charges (id. at 12-13, citing Eastern Edison Company, D.P.U. 92-148, at 36-37 (1992); D.P.U. 92-92, at 58-63). The Attorney General also argues that MIT has exaggerated the potential difference between the sum of the maximum monthly standby demand and 12 times the contract demand (id., citing Exh. HCL-14, at 17-18). Fourth, the Attorney General argues that MIT's assertion that the Company is treating half of the transmission and all distribution costs as related to non-coincident peak is contradicted by Mr. LaMontagne's unrebutted testimony that the Company's marginal distribution costs are adjusted to reflect the diversity between the Company's non-coincident class peaks and the annual coincident peak (id. at 13, citing Exh. HCL-14, at 20). Finally, the Attorney General asserts that a marginal cost rate is appropriate in the present circumstances as marginal costs better reflect the true cost of service for the Company to provide standby/supplemental service (id.).

d. BECo

BECo supports the Company's request for new standby rates (BECo Initial Brief at 1). BECo submits that the proposed rates for standby service are an appropriate first step in addressing the costs imposed by a cogenerator upon the remaining customers of the host utility's system (id.). BECo argues that the Company's proposed rates identify for the cogenerator the true costs of maintaining "on demand" standby power (id.). BECo also argues that the Company's proposed rates place on the customer who is imposing a cost on the system the responsibility for those costs (id.). BECo contends that the proposed rates are consistent with existing regulatory guidelines, including PURPA requirements (id.).

B. Maintenance Service Rate MS-1

The Company proposed a Maintenance Service Rate which is composed of the same marginal-cost-based administrative charge, customer charge, local T&D capacity charge, and energy charge as are included in the Company's proposed Standby Service Rate (Exh. HCL-1, at 23-24). The Company proposed to assess the local T&D capacity charge only once if a customer takes both standby and maintenance service in the same month (id. at 24; Exh. HCL-3).

The Company stated that maintenance service is intended to provide customers who have an alternative source of power with electric energy and capacity to replace energy and capacity ordinarily generated by the facilities that make up the customer's alternative source of power when such facilities are withdrawn from service for scheduled maintenance (Exh. HCL-1, at 4). According to Cambridge, maintenance service is distinguishable from standby service because of the customer's ability to pre-plan a maintenance-related outage (id.).

The Company also proposed to require that maintenance be performed in accordance with the following provisions: (1) maintenance is not scheduled for the months of January, July, August, and December; (2) the customer provides the Company with a preliminary written maintenance schedule by December 1, of each year; (3) the Company approves the maintenance schedule; and (4) the customer provides written notification to the Company of the dates and duration of the outage 30 days prior to the actual outage (id. at 24). Cambridge stated that these scheduling requirements are necessary in order for the Company to provide maintenance service with no G&OT capacity charges (id. at 25).

1. Positions of the Parties

a. MIT

MIT states that it is in agreement with Cambridge as to the general principle of maintenance service. However, MIT disagrees with: (1) the $300 administrative charge; (2) the level of costs included in the Company's proposed local T&D charge; and (3) the prohibition of maintenance service scheduled during January, July, August, and December (MIT Brief at 14 n.3).

Unlike Cambridge, who proposes a maintenance rate based on demand, MIT maintains that since a portion of maintenance can be done during off peak periods, like the Company's Experimental Rate X-2, the MIT project creates an opportunity to reduce loads on the Company's system during high-cost periods (Exh. MIT-182, at 28).

b. The Company

The Company argues that when a customer takes maintenance service, Cambridge incurs costs in providing local T&D and therefore, its proposed maintenance rate properly includes a local T&D capacity charge which is to be applied only if such charge is not otherwise billed under standby service for the particular billing month at issue (Company Brief at 130).

C. Supplemental Service Rate SS-1

According to Cambridge, supplemental service is intended to supplement the output of a customer's alternative source of power where the alternative source of power serves less than the customer's maximum electrical load (Exh. HCL-1, at 4-5). The Company's proposed Supplemental Service Rate is comprised of the same administrative charge as is included in the Company's proposed standby and maintenance service rates, and a customer charge, demand charge, and energy charge equal to the charges included in the applicable general service Rate G-3 (id. at 25).

MIT agrees that supplemental service should be provided under Rate G-3. However, MIT disagrees with the $300 administrative charge (MIT Brief at 13).

D. Analysis and Findings

The Department has previously approved rates for standby and maintenance service for various companies on a case-by-case basis. However, the specific structure of the rates varied from company to company. See Eastern Edison Company, D.P.U. 92-148 (1992); D.P.U. 92-92; Western Massachusetts Electric Company, D.P.U. 91-290 (1992); Nantucket Electric Company, D.P.U. 88-161/168 (1989). A review of the Department-approved standby, maintenance and supplemental rates indicates that the Department has not adopted a single method for the design of these rates, some of which were the result of settlement proposals approved by the Department. See Id. As such, there is no established Department precedent in this area. Accordingly, the Department's determination of the reasonableness of the Company's and MIT's proposed standby, maintenance, and supplemental rates in this case is guided by the Department's established rate structure goals as articulated in past Orders and discussed below.

We note that the Department has embarked on a course that would restructure the electric industry in Massachusetts. D.P.U. 95-30. In the process, the structure and pricing of standby, maintenance, and supplemental service may take various forms. For example, these services may be offered and priced under utilities' incentive regulation plans, or may eventually be subject to competitive forces and offered at market prices as opposed to cost of service. However, to date, Cambridge is the sole provider of standby, maintenance, and supplemental service to customers in its service territory, and as such, for the purposes of this case, pricing is based on the cost of the services and not the value of such services.

The Department has a well established policy that rate design should be based on marginal costs. See Western Massachusetts Electric Company, D.P.U. 86-280-A (1987); Western Massachusetts Electric Company, D.P.U. 85-270 (1986); Boston Edison Company, D.P.U. 85-266-A/85-271-A (1986). The Department has two rate design objectives to achieve its rate structure goals of efficiency, simplicity, continuity, fairness, and earnings stability. First, the rate design must be such that the rate structure for each given class produces revenues to cover the cost of serving that class. D.P.U. 86-280-A, at 177-178. This is necessary to achieve the goal of earnings stability. Id. Second, the rate design should be based upon marginal costs. Id. This furthers the Department's goal of promoting efficiency. Id. Efficiency in rate structure means that it is cost-based and reflects the cost to society of the resources consumed to produce the utility service. Id. Further, the Department noted that a marginal-cost-based rate design, as opposed to an average-cost-based rate design, provides customers with more accurate price signals of the cost of their consumption and enables them to determine their levels of use on a more appropriate basis. Id. at 178.

In designing class-specific rates, a company must reconcile the marginal-cost-based rates with the total class revenue requirements in order to ensure that the company recovers the allocated revenue requirement for the class. D.P.U. 85-270, at 242; D.P.U. 85-266-A/85-271-A, at 176. Since the Company in this case does not have any cost or load data specific to standby service to enable Cambridge to determine a revenue requirement, and in view of the fact that this is a new service offering, the Department finds that the Company's proposal to base its standby rate on full marginal costs is appropriate and is hereby accepted. Further the Department finds that the Company's alternative proposal and MIT's rate proposal, both of which are based on a disaggregated Rate G-3, are not appropriate because the present Rate G-3 charges were designed to recover a predetermined revenue requirement associated with the provision of service to an "all-requirements" class as opposed to a standby service class.

The following is the Department's analysis and findings as they relate to the individual charges proposed by the Company for its proposed standby, maintenance, and supplemental rates. We note that with respect to the Company's proposed supplemental service rate, all parties are in agreement that supplemental service at the 13.8 kV voltage level be priced at the Company's otherwise available rate schedule, Rate G-3. The only issue with respect to this rate is MIT's position regarding the appropriateness of the administrative charge. The Department finds that the Company's proposal to provide supplemental service under Rate G-3 is reasonable. The determination of an appropriate administrative charge is discussed below.

1. Administrative and Customer Charges

The Company has set forth documentation supporting Cambridge's proposed administrative charge (DPU-RR-2). In particular, the record shows the Company's development of the administrative charge, which includes costs associated with additional meters, meter readings, data programming, monitoring and translation, and billing determinant calculations (id.). All of these additional costs are incurred by the Company in providing standby, maintenance, and supplemental service and are not included in the determination of the Company's marginal customer costs (id.). MIT has provided no evidence to refute these costs. Accordingly, the Department finds that the Company's proposed administrative charge is supported by record evidence and is reasonable.

Consistent with our findings above, the Department finds that the Company's proposal to set the customer charge at full marginal customer cost is appropriate. Further, the Department notes that since there is no embedded revenue requirement associated with the Company's provision of standby and maintenance service, setting the customer charge at full marginal cost is appropriate and accepted. The Department rejects MIT's proposal to set the customer charge equal to the Rate G-3 customer charge, because such charge is based on the Rate G-3 revenue requirement and was not set at full marginal cost due to rate continuity considerations. The Department notes that under the Company's proposal, only one administrative charge and one customer charge will be assessed to a customer who takes any one or all three of these services (standby, maintenance, and supplemental).

2. Local T&D Capacity Charge

The Company's proposal to assess the local T&D capacity charge on the basis of a customer's contracted demand as opposed to actual demand, constitutes a demand ratchet. In the past, the Department has found that demand ratchets are inappropriate because they distort incentives to conserve and could unfairly impose higher costs on certain customers. Massachusetts Electric Company, D.P.U. 92-78, at 188 (1992); Western Massachusetts Electric Company, D.P.U. 86-280, at 196 (1987); Western Massachusetts Electric Company, D.P.U. 84-25, at 199 (1984).

The Company has presented no new evidence or argument that would persuade the Department to alter its policy on this matter. Moreover, in the absence of standby class-specific load data, the Department is not convinced that assessing a distribution demand charge on the basis of actual demand as opposed to contracted demand would cause the Company to under-recover distribution-related costs. Indeed, the opposite could also hold true. That is, the Company, over the course of a year, may over-recover distribution-related costs if it were to assess the distribution demand charge on the basis of contracted demand. This is because a customer's total annual billing demand is likely to be lower than 12 times the maximum monthly demand since no customer has exactly the same demand in every month. Accordingly, the Company's proposal to apply the local T&D capacity charge on a customer's contracted demand is hereby denied. Instead, the Company is directed to apply the distribution demand charge approved by the Department on a customer's actual monthly demand.

The Company's proposed local T&D capacity charge is equal to the sum of Cambridge's marginal local transmission costs and marginal distribution costs. In D.P.U. 92-250, at 180-182, Cambridge proposed to allocate a portion of its distribution costs, namely its 13.8 kV bulk distribution plant, on the basis of a PR allocator, and argued against the use of a non-coincident peak allocator. The Company asserted that although its 13.8 kV system was classified as distribution plant for accounting purposes, given the density of population, its bulk substation facilities were relied upon by all customers and served the same purpose as transmission facilities in other service areas. Id. at 182. The Department noted that based on the record in that case, the Company's bulk substation plant was shared by all of Cambridge's customers, and that the facilities served the same purpose as transmission facilities do in the service areas of other utilities. Id. at 183. Accordingly, the Department accepted the Company's proposal to allocate its 13.8 kV bulk substation facilities based on a PR allocator. Id. at 184.

In this case, the Company's proposal to recover costs associated with its local transmission facilities and 13.8 kV facilities via its proposed local T&D capacity charge is inconsistent with its position in its last rate case regarding the functionalization of these costs, and regarding the Department's findings that Cambridge's 13.8 kV bulk substation facilities were used and served the same purpose as the Company's transmission facilities. The record in this case indicates that the Company's 13.8 kV bulk substation facilities continue to perform the same function as in the Company's last rate case (Tr. 7, at 151). Accordingly, the Department finds that it is inappropriate for the Company to recover local transmission, and bulk substation costs via the distribution demand charge. Rather, such costs may be recovered through the Company's G&OT charges as shown in the Company's response to DPU-RR-4. In its compliance filing, the Company is directed to reflect a distribution demand charge as shown in Cambridge's response to DPU-RR-4.

3. G&OT Capacity Charge and G&OT Capacity Reservation Charge

The Department finds that MIT's proposal to prorate the G&OT charge on a daily basis is inappropriate because it is inconsistent with the manner in which the Company incurs costs. The costs associated with G&OT investments and commitments are long-lived in nature and reflect the Company's long-range planning decisions. As such, these costs are not incurred on a daily or an hourly basis, nor does the Company contract for capacity on an daily or hourly basis. Further, record evidence indicates that if capacity costs are prorated on a daily basis and standby loads are established based on FOR expectations, the Company will under-recover the capacity costs it incurs to serve the standby customers (Exh. MIT-185). Accordingly, the Department finds that the Company's proposal to assess G&OT charges on a monthly basis is reasonable.

Regarding the design of the G&OT capacity reservation charge, the Department notes that such a charge must be designed to ensure that the cost of standby customers' required reserve capacity is recovered from standby customers and not imposed on the Company's other customers. In turn, the level of standby reserve capacity that the Company is required to serve is a function of the expected diversity among self-generator outages in the Company's system. However, since standby service is a new service offering, the Company has no information specific to a standby class that would reflect the expected diversity among self-generators, and which could in turn be used in the determination of an appropriate reservation charge for G&OT capacity costs. Nevertheless, it is inappropriate to base the G&OT capacity reservation charge upon the FOR of a hypothetical self-generator because it may not reflect how the Company incurs costs to serve standby load.

The Department finds that for the purposes of this case, the Company's proposal to reflect the NEPOOL reserve margin requirement to calculate the G&OT capacity reservation charge is appropriate because that margin considers the level and diversity of the Company's load, its generation resources, and the regional generation resources which are made available to the Company as a NEPOOL member. Therefore, since the Company is likely to satisfy the standby load with generation capacity from its reserve margin, it is reasonable to reflect the reserve margin requirement in the determination of the costs associated with the Company standing ready to meet standby customers' needs.

Regarding the Company's proposal to charge standby customers the greater of the G&OT capacity reservation charge or a usage charge, i.e., the G&OT capacity charge, the Department finds that, contrary to MIT's assertion, a customer would not be double-charged for the use of G&OT capacity under the Company's proposed standby rate. This is because the cost of providing standby service is a function of both the cost associated with the amount of load that the utility must plan for -- recovered via the reservation charge -- and the capacity actually used. The function of the monthly G&OT capacity charge is to recover costs incurred by the Company over and above the reservation charge based on actual usage by the standby customer of capacity provided by the Company (Tr. 7, at 175). Accordingly, the Department finds that the Company's proposal to charge standby customers the greater of the G&OT capacity reservation charge or the G&OT capacity charge is appropriate.

Consistent with our finding regarding the exclusion of local transmission and 13.8 kV bulk substation costs from the Company's proposed local T&D charge, and the assignment of these costs to the G&OT charges, the Department notes that the appropriate G&OT capacity charge and G&OT capacity reservation charge are contained in the Company's response to DPU-RR-4. The Company is directed to reflect these charges in its compliance filing.

4. Energy Charge

The Department notes that no party addressed the reasonableness of the Company's proposed energy charge for standby and maintenance service. The Department finds that the Company's proposal to set the energy charge for these services equal to the energy purchase rates at the appropriate voltage level contained in Rate P-1 less the applicable fuel charge is reasonable. Further, the Department accepts the Company's proposal that standby energy be subject to the conservation charge and the fuel charge that may be applicable under the rate schedule for which a standby service customer would qualify if the customer did not own and operate generating facilities.

5. Scheduling of Maintenance Service

The Company proposes that maintenance service not be scheduled for the months of January, July, August, and December, which are the peak months for the ComElectric system. The Department finds that the Company's proposal to allow maintenance service only during the off-peak months is rational because there is little chance of the Company establishing a new peak during these months, and therefore there should be no impact on the level of capacity that the Company has to have in place to provide the service. Similarly, the Company's capacity requirements should not be impacted by maintenance service that occurs during the off-peak hours of the peak months. Therefore, the Company's customers should be allowed to schedule maintenance service during the off-peak hours of the peak months. To the extent that maintenance service can be scheduled to coincide with the off-peak hours of the peak months, such service would not impose any additional capacity burden on the Company. However, the Department finds that if maintenance service extends beyond the off-peak hours of the peak months, the loads established during the peak period of the peak months should be considered standby loads and not maintenance loads and priced accordingly.

Therefore, in its compliance filing, the Company is directed to revise the "Scheduled Maintenance" provision of its proposed Rate MS-1 to reflect the Department's findings regarding this issue.

6. Distribution Investment Credit

MIT contends that it should receive a $1.4 million credit to the standby service rate to recognize its payment toward incremental distribution facilities pursuant to an Interconnection Agreement. Although MIT made this argument in its original petition under D.P.U. 94-101, it made no mention of its position during the consolidated proceeding, D.P.U. 94-101/95-36 until its reply brief. MIT provided no evidence during this proceeding regarding the justification of this credit or the accuracy of the amount of the investment. Accordingly, the Department finds that a credit is inappropriate and is not allowed.

VI. CUSTOMER TRANSITION CHARGE RATE CTC-1

The Company proposed that a customer who is discontinuing all or a portion of all-requirements firm sales service from the Company and meets the following criteria be subject to the CTC: (1) the customer had an average billing demand of 2,000 kVa or greater for the most recent calendar year; (2) the customer obtains electric service from a source other than the Company; and (3) the customer remains within the Company's service area (Exhs. HCL-1, at 27; HCL-11). The Company proposed a customer transition charge of $7.49 per kVa to be assessed to all applicable customers on a monthly basis (Exh. HCL-11). This charge would be applied to the "reference customer demand" which the Company defined as either the customer's firm standby contract demand, or if the customer does not take standby service, the peak demand established by the customer for the most recent 12- month period prior to the customer's written notice of discontinuing service from the Company (Exh. HCL-1, at 27-28).

Cambridge proposed that the CTC be effective upon a customer's departure through December 31, 2000 (id. at 28). Further, the Company proposed that this rate change prior to year 2000 only if there is a: (1) significant change in current market surplus capacity; (2) major industry restructuring which affects Massachusetts; or (3) a general rate case filing by the Company (id.).

The Company stated that it developed its proposed CTC in an effort to advance the following objectives. First, the CTC is intended to establish a cost-based mechanism for the

Company to recover stranded costs from a departing customer who has responsibility for those costs[15] (Exh. WJO-1, at 2). Second, the design of the CTC is intended to ensure that the charge is both equitable and efficient in addressing the potential costs associated with a customer being able to take advantage of alternative supply options (id.). According to Cambridge, the third objective of the CTC is to establish a sound conceptual and theoretical basis for the method that avoids cost shifting and cross-subsidies among the Company's customer classes (id.). Finally, the Company stated that its fourth objective was to develop a comprehensive approach which considers the Company's system as a whole, and is not administratively burdensome (id. at 3).

The Company stated that presently, seven of its customers have average monthly demands in excess of 2,000 kVa, and therefore these customers would be subject to the transition charge if they were to take power from an alternative supplier ("load at risk class")[16] (Exh. RDW-1, at 19). Cambridge further stated that collectively, these seven customers represent a coincident peak demand of 61.5 MW or 21.2 percent of the Company's peak load (id. at 28). Total revenues from

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15 According to the Company, the proposed CTC recognizes the "regulatory compact" between franchised utilities and their regulators (Exh. WJO-1, at 2). The Company stated that the regulatory compact establishes a basis for recovery of prudently incurred costs and a fair rate of return on invested capital (id.).

16 The Company determined the load-at-risk class by performing an analysis of the Company's 1994 average billing determinants for all accounts within the Company's system (Exh. HCL-1, at 30-31). Cambridge analyzed the usage and revenue levels of the accounts to determine whether there was a distinct point on the usage and revenue continuum which would provide a threshold for determining loads whose loss would have a significant impact on the Company (id.). Based on this analysis, the Company determined that at an average monthly demand level of 2,000 kVa the customer load levels increased rapidly while the number of customers decreased rapidly. The Company further determined that the loss of a customer whose monthly demand exceeded the 2,000 kVa threshold would reduce Company earnings by nearly 11 percent. Thus, the Company defined a load-at-risk class consisting of seven customers with loads greater than 2,000 kVa per month (id. at 31).

these customers in 1994 were nearly $24 million, which is 19 percent of Cambridge's total annual revenues (id.).

The Company employed the following steps in determining the CTC. First, it calculated a revenue requirement amount ($20,985,742) for the load at risk class[17] and subtracted from this amount an amount equal to the avoidable variable expenses ($5,796,162) that would not be incurred as a result of the load at risk customers leaving the system (Exh. HCL-1, at 29-30). This subtraction resulted in a revenue requirement figure of $15,189,580 which the Company stated represented the gross amount of stranded costs associated with the load at risk class (id. at 32).

Second, the Company reduced or mitigated the amount of gross stranded costs for the load at risk class by the amount of (1) expected revenues from continued services provided to the customers, (2) potential revenues from reselling the generating capacity available to be marketed as a result of the customers departure, and (3) the revenues associated with anticipated load growth on the Company system (id. at 32-34). The removal of these three mitigation components yielded an annual net stranded cost amount of $6,007,100 (Exh. HCL-12).

The Company calculated the revenues associated with continued services by applying the minimum charges[18] of the standby service tariff to the amount of load at risk. This calculation produced an annual revenue amount of $4,524,400 (Exh. HCL-1, at 32-33). The Company

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17 The Company stated that its compliance cost-of-service study approved in D.P.U. 92-250 was used as a base case scenario for the calculation of the stranded costs (Exh. HCL-1, at 29). From this starting point, the Company recalculated the cost of service by disaggregating the amount of load at risk into a separate class resulting in an allocated revenue requirement for the load at risk class (id. at 29-30).

18 The minimum charges applied were the customer charge, the administrative charge, the local T&D capacity charge, and the G&OT capacity reservation charge (Exh. HCL-1, at 32).

applied the market value of the stranded generation capacity[19] to the capacity portion of the amount of load at risk in order to calculate the amount of potential revenue associated with the resale of generating capacity that is no longer needed to provide service to the load at risk (Exh. WJO-1, at 29-33). Cambridge determined that this second mitigation factor amounted to $3,049,500 per year (Exh. HCL-1, at 33). In order to arrive at the revenue associated with anticipated load growth, the Company applied the average load growth for the system[20] to the Company's average base rate per KWh. This calculation produced an annual revenue amount of $1,608,900 (id. at 34). Finally, the Company divided the annual net stranded costs by the annual load of 66,806,000 kVa (load at risk) associated with the seven customers to arrive at its proposed $7.49 per kVa, per month, CTC (Exh. HCL-12). The Company stated that under its proposed CTC, the Company would recover approximately 40 percent of the gross stranded costs (Exh. HCL-14, at 27-28).

A. Positions of the Parties

1. MIT

MIT's argument against Cambridge's proposed CTC is broken down into several

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19 The Company stated that it identified the most applicable competitive options within the New England wholesale power market as a basis for its market value assessment and used the pricing terms of these options to develop an annual weighted capacity charge (market price) for each year of the calculation period, 1995 through 2000 (Exh. WJO-1, at 30-33).

20 The Company used its latest demand forecast approved by the Department in Cambridge Electric Light Company and Commonwealth Electric Company, D.P.U. 91-234 (1993) to derive the annual compound growth rate between the actual 1994 coincident peak demand for the Company and the peak demand projected for the year 2000, the final year of the calculation period (Exh. HCL-1, at 33-34, citing D.P.U. 91-234). Cambridge applied this growth rate to the actual 1994 peak demand for the system to calculate the average annual load growth for the system over the calculation period (id. at 34).

criticisms. According to MIT, the Company's proposed CTC is: (1) premature; (2) premised on the incorrect assertion that the Company has surplus capacity; (3) premised on the incorrect assertion that the Company has surplus costs; (4) based on problematic calculations; (5) based on faulty economics; (6) incorrectly applied to certain types of customers; and (7) bad policy (Exh. MIT-182, at 34-53; MIT Brief at 34-68).

First, according to MIT, the Company's proposed CTC would impose a punitive charge on MIT, which the Company is trying to disguise as an aspect of industry restructuring (Exh. MIT-182, at 34; MIT Brief at 35). MIT asserts that although the Company points to changes in the electric industry due to competitive forces in the market place as a reason for the Company to implement the CTC, MIT's cogeneration plant has nothing to do with industry restructuring. MIT argues that the Company has failed to establish that its claim for stranded cost recovery is supported by a "regulatory compact" and exclusive franchise rights (MIT Reply Brief at 14-19). MIT claims that cogeneration has been an option for many years and has been national policy since such technology was encouraged under PURPA since 1978 and that its project, which has begun operation, is part of normal business risk (Exh. MIT-182, at 36, 45, 51; MIT Brief at 35-37, 39-40). Moreover, according to MIT, the Department should not determine issues related to the restructuring of the electric industry in this case (MIT Reply Brief at 12).

Second, MIT argues that Cambridge's position on both capacity planning and its year of need for new capacity is inconsistent (id. at 43). For example, MIT asserts that, originally, the Company tied the CTC to what it characterized as a capacity surplus situation until 2001, but that MIT found evidence that both Cambridge and Cambridge and Commonwealth as a system (referred to as "COM/Electric") had little if any surplus capacity (Exh. MIT-182, at 38-41; MIT

Brief at 38, 41-49). According to MIT, this realization is confirmed by the fact that in February 1995, Commonwealth signed a contract for the purchase of 75 MW of peaking capacity and associated energy from Northeast Utilities Service Company ("NUSCo") (MIT Brief at 46). MIT contends that the Company then claimed that the relevant surplus in terms of the importance of the CTC was the surplus capacity in the New England region, not COM/Electric (id. at 48, citing Exh. HCL-14, at 38).

Third, according to MIT, the Company initially identified the difference between embedded cost and marginal cost as a cause of stranded costs, but that later the Company's position developed into the difference between embedded cost and market prices as being the cause of stranded costs (id. at 50). MIT maintains that the Company has not provided evidence that it has surplus costs under either definition (id.). With regard to the discrepancy between embedded and marginal costs, MIT argues that the Company's updated marginal capacity costs exceed its embedded costs and that Cambridge did not provide any evidence to support its claims of the disparity between marginal and embedded costs for transmission and distribution (id. at 51, citing Exh. MIT-86a). With regard to the discrepancy between embedded costs and market prices, MIT asserts that the Company overstated the discrepancy and never supported the claim that its average cost of supply is 5.3 cents per kWh (id. at 51, citing Exh. HCL-14, at 36-37). According to MIT, the average current cost of Cambridge's purchased power supply is 4.4 cents per kWh versus that of new supply sources between 4.5 cents and 5.0 cents per kWh (Exh. MIT-182, at 39-40). MIT further maintains that the difference between embedded casts and the market price "is not relevant to a competitive market with retail customer access to the market," because customers cannot buy power on the wholesale market (MIT Brief at 52).

Fourth, MIT also argues that stranded costs would always exist given the way in which the Company calculated the CTC (Exh. MIT-182, at 48). MIT outlines what it asserts are problems in the calculation of the CTC: (1) the use of a 1992 cost study is outdated and does not incorporate the Company's cost-savings since then, such as employee level reductions; (2) gross stranded costs are overstated, because only avoidable fuel and purchased power expenses equal to 1.77 cents per kWh[21] (an amount lower than the Company's Rate P-1) were eliminated from the load at risk revenue requirement calculation; (3) the CTC is calculated on all of the load at risk at one point in time, even though the CTC is sensitive to the assumption of when load at risk will be reduced, due to fluctuations in market prices over time; (4) the offset for customer growth is understated, because the average base rate used as the proxy for revenues does not include capacity-related costs recovered through the fuel charge;[22] (5) the offset from revenues is not realistic, because the Company only assumes the minimum standby service charges that would be collected, assuming no outages; and (6) the offset from revenues from the resale of freed-up generating capacity is understated, because only capacity charges are included (Exh. MIT-182, at 48-50; MIT Brief at 55-58, 62-65). MIT also takes issue with the Company's statement that the CTC would provide an opportunity to recover only 40 percent of gross stranded costs; MIT argues that the CTC would guarantee the Company recovery of at least 40 percent of gross

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21 MIT arrived at 1.77 cents by dividing the $5,796,162 million reduction to the load at risk revenue requirement by the seven customers' total kWh of 325,876,709 kWh (MIT Brief at 55, citing Exhs. MIT-95; MIT-108, Att.).

22 MIT takes issue with the Company's claim that including the effect of fuel charge capacity recovery would "not be material" (MIT Reply Brief at 38, citing Company Brief at 79-80, n.20). According to MIT, this would reduce the CTC from $7.49 per kVa to $7.00 per kVa, or approximately $118,000 per year ($0.49 X 20,000 kVa X 12) (id. at 38).

stranded costs (MIT Brief at 65, citing Tr. 7, at 137-138).

Fifth, contrary to the Company's assertion that the MIT project will increase costs to other customers, MIT asserts that public utility economic theory suggests that, over the long-term, the impact of the MIT project should decrease costs to other customers (id. at 58-59). MIT argues that Cambridge will avoid the incremental costs of new capacity, because the MIT project defers the need for such capacity (id. at 9).

Sixth, MIT contends that although Cambridge claims that the CTC is not just for MIT, the Company has indicated that none of the other six customers for whom the CTC is designed are planning on leaving the system (id. at 35). Moreover, according to MIT, the application of the CTC to the reference customer demand may elicit unusual outcomes in potential customers' billing (id. at 66). Specifically, MIT posits the following examples:

> A 3,000 kVa customer who installs a 1,000 kVa of self-generation and contracts for 1,000 kVa of standby service would pay the CTC for 1,000 kVa of load .... If that customer decided to buy 500 kVa of standby service instead of 1,000 kVa, it would pay the CTC on 500 kVa. But if the customer decided to buy no standby service, it would have to pay the CTC for the full 3,000 kVa of load...even though it continued to buy 2,000 kVa of supplemental service. This means that a 3,000 kVa customer who installs 10 kVa of photo-voltaic cells on its roof would be charged for 3,000 kVa times the CTC rate

(id.).

Finally, MIT asserts that implementation of the CTC is bad policy for the Company and for the City of Cambridge, because it promotes poor business relations with customers (Exh. MIT-182, at 50; MIT Brief at 66-67). Moreover, according to MIT, the language relating to the term of the CTC is vague and ambiguous as to the precise timing and effect of Cambridge revisiting the CTC by 2001, and thus would confuse customers (Exh. MIT-182, at 50; MIT Brief at 66-67).

2. The Attorney General

According to the Attorney General, while the Department had clear authority under Chapter 164, § 94, to approve a tariff such as the CTC, the Company's proposed CTC should be rejected (Attorney General Brief at 6). The Attorney General contends that it is clear that the Company has been on notice since at least 1985 that MIT was actively considering self-generation and that the Company did not undertake any meaningful effort to mitigate the foreseeable consequences of losing MIT as a full requirements customer (id.). The Attorney General suggests that the Company's load forecasting and resulting acquisitions activities proceeded until 1991 as if MIT undoubtedly would remain a full requirements customer (id. at 7-8, citing Commonwealth Electric Company/Cambridge Electric Light Company, 22 DOMSC 116 (1991); Commonwealth Electric Company/Cambridge Electric Light Company, 12 DOMSC 39 (1985); Commonwealth Electric Company/Cambridge Electric Light Company, D.P.U.91-234, at 42,44 (1993)). The Attorney General posits that the "Company has not demonstrated in this proceeding that the costs in question were incurred prudently, i.e., that their incurrence was reasonable in light [of] the lack of a basis to assume MIT would remain a total requirements customer and that all reasonable steps were taken to mitigate any costs that were incurred prudently" (id. at 9). In the Attorney General's view, this position is clearly supported by the Department's Order in D.P.U. 95-30 (Attorney General Reply Brief at 1-2). The Attorney General contends that in the event the Company does make such a demonstration, and the Department determines that the Company should recover some or all of the costs "stranded" by MIT, the recovery must come from MIT (Attorney General Initial Brief at 9). According to the Attorney General, "responsibility for these cost[s] must be borne by one of the two entities whose actions gave rise to those costs, either the Company's shareholders or the departing customer" (id.; Attorney General Reply Brief at 4).

3. The City of Cambridge

According to the City, the Department should abstain from ruling on the present case until it has ruled on D.P.U. 95-30, to ensure comprehensive treatment of the issues that give rise to stranded costs and the recovery of such costs (City Initial Brief at 4). The City draws an analogy between the present case and D.P.U. 95-30 arguing that the present case is akin to a proceeding before a federal district court raising narrow issues particular to the Company in a case commenced when D.P.U. 95-30 was pending before a Massachusetts court raising global industry-wide issues with application to the Company as well as other utilities (id. at 8-9).

Alternatively, the City asserts that the Department should find that the stranded costs should not be borne by the remaining customers, but by the Company and MIT who were both aware of MIT's cogeneration plans and assumed the attendant risks (id. at 12). The City contends that the Company had a duty to mitigate the costs which would be stranded by MIT and that the Company did not take any measures to mitigate the financial consequences of MIT's cogeneration facility (id. at 12-13). In support, the City argues that the Company did not begin planning for MIT's departure until 1993, when the Department suggested that the Company consider doing so (id. at 14, citing Exh. 170, at 2). Further, the City argues that between 1985 and 1992, when the Company knew of MIT's cogeneration plans, the Company continued to enter into multi-year capacity purchase contracts, the shortest such contract being for a term of 15 years (id. at 15).

The City further argued that the Company should not be allowed to recover stranded costs from its remaining customers (id. at 16). The City stated that it has "deep reservations" about the "regulatory compact" on which the Company bases its claim for stranded cost recovery (id. at 17). According to the City, it was the Company's own failure to prepare for the emergence of cogenerators in its customer base that created the stranded costs it now seeks to recover (id. at 18-19).

4. BECo

BECo supports the Company's proposal (BECo Brief at 1). BECo notes that unlike customers who choose to leave a system by vacating premises which may be occupied by a new customer, MIT will remain in the Company's service territory and the Company will have no opportunity to recover costs associated with investment made to serve MIT (id. at 1-2). BECo submits that the imposition of the CTC will allow a customer seeking to by-pass the host utility's system to assess its decision based on the true economic costs associated with that decision (id. at 2).

5. WMECo

WMECo states that it is important to consider the Company's proposed CTC in the context of the overall fundamental electric industry restructuring now evolving (WMECo Initial Brief at 2). WMECo posits that the same factors that are driving electric industry restructuring also provide an impetus to utilities' largest customers to self-generate, i.e., new legal, regulatory, technological and market developments, as well as intensified global competition (id.). WMECo notes that self-generation has been an option for large industrial customers in the past (id.). WMECo argues, however, that the practical viability of self-generation has significantly increased in recent years because of numerous factors including substantial improvements in combined-cycle generation technologies, low fuel input costs, regulatory changes affecting the gas and electric industries, and the current disparity that exists between utility embedded costs and the cost of alternative sources of supply on the market (id.). WMECo states that cost shifting from a customer who takes advantage of recent competitive alternatives to remaining ratepayers must be avoided (id.).

6. The Company

The Company asserts that its proposed CTC is consistent with the "regulatory compact" that has existed between utilities and their customers and as such, it establishes a cost-based mechanism for Cambridge to recover stranded costs directly from the customer who bears the responsibility for those costs being incurred (Company Brief at 21-24).[23] According to Cambridge, the Company's obligation to serve requires the Company to plan its system to meet the existing and expected loads of all of its customers (id. at 25). Cambridge maintains that in doing so, the Company incurs significant levels of fixed costs, and therefore, actions on the part of the customers to secure alternatives will likely result in costs being stranded (id. at 25-26).

The Company asserts that past forecasting and planning decisions that proved to be incorrect, along with recent technological and market changes, have exacerbated the potential for stranded costs (id. at 28-29, 31-33). Further, according to Cambridge, certain legal and regulatory developments have either contributed to the existence of stranded costs or are likely to increase the magnitude of stranded costs in the future (id. at 29-30). The Company argues that the most equitable and economically efficient method to collect stranded costs is to assign such costs directly to those customers on whose behalf they were incurred (id. at 35). Cambridge asserts that this direct assignment of stranded costs to the departing customer[24] would serve to

[23] The Company also asserts that its proposed CTC is consistent with principles established by the FERC in Notice of Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking, 70 FERC ¶ 61,357 (1995) (Company Brief at 46-48).

send the proper price signals[25] to customers and prevent the economically inefficient outcome known as uneconomic bypass (id. at 35-36).

The Company claims that it is not appropriate, equitable, or lawful for investors to bear the risk of non-recovery associated with prudent costs incurred in meeting the Company's obligation to serve (id. at 41-45). Cambridge argues that as long as the costs included in rates and approved by the Department have been prudently incurred, those costs should not be borne by shareholders, or bondholders, if such costs are caused to be stranded by a customer taking service from an alternative supplier, including the customer itself (id. at 45).

Addressing MIT's assertion that self-generation has been a competitive reality for a significant amount of time and that this case is not an appropriate forum in which to address stranded costs, Cambridge argues that although self-generation has been a theoretical option in the past, the viability of self-generation has significantly increased in recent years because of factors such as improvements in generating technologies, low fuel input costs, improvements in plant efficiency, and regulatory changes affecting the gas and electric industries (Company Brief at 60-61).[26] Further, the Company asserts that these same factors are driving industry

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24 The Company asserts that the direct assignment of stranded costs is consistent with both Department and FERC policies (Company Brief at 39-40).

25 According to Cambridge, the application of its proposed CTC will provide customers who are seeking alternative sources of supply with the ability to include all costs in their decision-making process and ensure that the decision is economically efficient (Company Brief at 39).

26 The Company claims that the record indicates that MIT's witness acknowledged that self-generation has become increasingly competitive as a customer option, reflecting the changes that have occurred and are continuing to occur in the industry (Company Brief at 62-64; Company Reply Brief at 13).

restructuring and that the Department has not addressed the impacts on other customers resulting from some customers seeking alternatives such as self-generation.[27] Thus, the Company contends that this is an appropriate case to address its proposed CTC (id. at 63-64).

The Company contends that its proposed CTC rate is cost-based and is applicable to a class of customers with more members than just MIT (Exh. HCL-14, at 31). According to the Company, the fact that currently only MIT would be subject to the tariff does not make the CTC an "MIT only" rate (id.). The Company asserts that given the increased sophistication of customers regarding their options in the electricity market, it expects that additional large customers could be subject to the CTC in the future (id.).

Cambridge argues that its proposed CTC rate is not an attempt by the Company to penalize MIT (id. at 32). The Company asserts that the CTC follows appropriate cost-causation principles by assigning cost responsibility to the class of customers for whom the costs were reasonably incurred, and as a result, the CTC is not a punitive charge and does not represent an attempt to prevent self-generation or other forms of customer bypass (id.).

Regarding MIT's claim that the CTC is too late because the MIT project is committed, Cambridge contends that the fact that the MIT cogeneration project is committed is a function of MIT's timing and decision making and not the Company's (id. at 33). With respect to MIT's argument that the CTC is premature, Cambridge maintains that although the Department has yet to direct a broad industry restructuring, substantial steps in that regard are now underway in D.P.U. 95-30, and the CTC is very compatible with the direction the electric industry is likely

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[27] The Company points out that FERC has also recognized the improved economics of self-generation as one of the key factors driving certain customers to seek alternatives to all-requirements service from their host utility (Company Reply Brief at 15).

headed (id. at 34).

Addressing MIT's arguments regarding the capacity need of Cambridge and its relevance to the existence of stranded costs, the Company argues that stranded costs are not just a function of excess capacity on its system, but are also directly affected by the value of capacity in the relevant market (id. at 35). According to the Company, stranded costs are a function of the difference between embedded costs and market prices, and that when a customer leaves the utility system, it strands not only generation costs, but costs such as regulatory assets, deferred costs and DSM costs (id. at 35-36).

The Company also takes issue with MIT's claim that no costs will be stranded as a result of MIT's departure (id. at 36). The Company argues that MIT has understated the differential between the Company's embedded costs and market prices (id.). Cambridge contends that the embedded cost for the Rate G-3 class is approximately 5.3 cents per kWh, including capacity and energy, and not 4.4 cents per kWh as MIT would argue (id. at 37). Further, according to the Company, the spot market price for electricity is around 2.5 cents to 3.00 cents per kWh, and not the 4.5 cents to 5.00 cents per kWh estimate provided by MIT (id. at 36-37). Therefore, the Company contends that contrary to MIT's claims, and given the current market for power, Cambridge would experience stranded costs of over 2.5 cents per kWh for each kWh not purchased by MIT (id. at 37).

The Company argues that the market faced by Cambridge in its efforts to resell capacity stranded by a departing customer is the regional wholesale power market (Company Reply Brief at 42). Therefore, according to the Company, MIT's assertion that customers cannot buy power on the wholesale market may be correct, but it is irrelevant to an appropriate determination of the

Company's ability to mitigate stranded costs (id.).

Addressing MIT's contention that under the Company's proposed method stranded costs will always exist when a customer leaves the system, Cambridge argues that such a claim is not true because in a situation where embedded costs are lower than or equal to prevailing market prices, stranded costs would not occur if a customer left a utility system because the utility could mitigate what would have been stranded through the resale of electricity (Exh. HCL-14, at 39-40). Further, the Company disputes MIT's assertion that Cambridge provides two definitions of stranded costs. The Company maintains that the difference between the utility's embedded costs and the market value of power is the amount of costs that are stranded (Company Reply Brief at 18-19).

Regarding the issue of capacity need, the Company asserts that contrary to MIT's claim, Cambridge and Commonwealth plan their systems on an integrated basis and that there are benefits that flow through to each company's customers (Company Brief at 85). Further, the Company maintains that it still anticipates having a need for capacity no sooner than the summer of 2001, as determined by the Department in COM/Electric's last Integrated Resource Management ("IRM") proceeding in Cambridge Electric Light Company and Commonwealth Electric Company, D.P.U. 91-234 (1993) (Exh. HCL-14, at 39). Finally, Cambridge contends that Commonwealth's peaking power purchase from NUSCo was not made because of a capacity need for the Company or Commonwealth, but rather as a power optimization process undertaken by Commonwealth (Company Brief at 86).

Responding to MIT's assertion that Cambridge's calculation of stranded costs includes costs that are no longer part of the cost of the system, such as the Northeast Utilities slice-of-system contract, the Company argues that the costs associated with that contract were never included in Cambridge's base rates, and were always recovered through the Company's fuel charge (Company Reply Brief at 37-38). Further, the Company argues that MIT's attempt to support an overall conclusion that the Company's costs have decreased by focusing on only one isolated source of costs since the last rate case is incorrect and contrary to long-standing ratemaking principles (id. at 38). Cambridge asserts that since its last rate case, it has experienced cost increases in several areas such as the demand portion of purchased power expenses, income and property taxes, and plant in service, all of which more than offset any cost reductions referenced by MIT (id. at 38-39).

Responding to MIT's argument that the Company has underestimated the value of fuel and purchased power savings used to offset Cambridge's gross stranded costs, the Company argues that MIT's calculation of 1.77 cents per kWh is based on the number of kWh associated with the load at risk for the calendar year 1994 (id. at 43). The Company maintains that its avoidable fuel estimate of $5.8 million is based on the Company's 1992 test year, and that if this number is divided by the test year sales, the result would be an avoided cost of approximately 1.9 cents per kWh (id.). Further the Company takes issue with MIT's reference to the Company's avoided cost of fuel for the second quarter of 1995, arguing that figure reflects a single quarter only and is not fairly representative of an average avoided cost over a full calendar year (id.).

The Company argues that contrary to MIT's claim, the offset for customer growth is not understated because in calculating the mitigation for load growth, it is not possible to determine from which customer sector that growth will occur, and thus, it is reasonable to apply the Company's overall average base rate per kWh to project the associated revenue offset (Exh.

HCL-14, at 47).

With respect to MIT's criticism concerning the crediting of only the minimum standby charges in the CTC, the Company contends that it properly credited only the minimum standby charges for three reasons (id. at 47). First, use of only the minimum charges is appropriate for the purposes of administrative simplicity; and estimating standby revenues would be a speculative exercise (id. at 47-48). Second, according to Cambridge, any understating of standby revenues would be offset in the area of mitigated power sales (id. at 48). The Company maintains that to the extent that more power is assumed and sold under standby service than assumed through minimum charges, less power would be able to be resold at the presumed market value (Company Brief at 84). Finally, the Company argues that the assumed mitigation values for the CTC are favorable to any customer on the rate because in practice, it is more likely that the Company will have difficulty achieving the sales at the prices assumed in the rate, and that not all power made available can be resold (Exh. HCL-14, at 48).

Addressing MIT's contention relating to the vagueness in the CTC tariff regarding its term, the Company maintains that it did not intend to be cryptic in designing the rate and identifying its term (id. at 48-49). Therefore, the Company states that it would support modifying the language in the tariff to make it clear that the CTC would be amended or replaced, as appropriate, upon the sooner to occur of:

(a) a subsequent order of the Department in a base rate proceeding relating to the Company or regarding an alternative rate proposal of the Company;

(b) a subsequent order of the Department that revises the regulatory structure applicable to electric utilities and/or that establishes new rate methodologies and processes to be applicable in the future; or

(c) December 31, 2000 (id. at 49).

In its reply brief, the Company asserts that its proposed CTC comports in all respects with the standards and underlying policy rationale regarding stranded cost recovery as set forth by the Department in D.P.U. 95-30 (Company Reply Brief at 6). In particular the Company contends that its CTC: (1) complies with the D.P.U. 95-30 requirements that appropriate mitigation be included in a stranded cost recovery mechanism; (2) avoids anticompetitive effects as enunciated in D.P.U. 95-30; (3) meets the duration standard in terms of the number of years over which stranded costs are to be recovered; and (4) is non-discriminatory and non-bypassable to all customers (id. at 9-12).

Cambridge contends that if the stranded cost issues confronting the Company are not addressed in this case, significant cost shifting to other customers would result in a manner inconsistent with the Department's stated policy in D.P.U. 95-30 (id. at 6). The Company reasons that since the CTC would be superseded by a more universally applicable stranded cost recovery mechanism adopted by the Department to effect industry restructuring, the approval of the CTC in this case would not limit the Department's options regarding the treatment of stranded costs in the context of industry restructuring plans or other proceedings down the road (id. at 6-7).

Regarding the Attorney General's and the City's contention that the Company has not shown that the costs in question were prudently incurred, the Company argues that its proposed CTC includes only those costs which the Department has previously determined were prudently incurred and consistent with the Company's obligation to serve (id. at 20-21). Further, the Company maintains that it has acted prudently over the years to avoid stranded costs by attempting to find a mutually agreeable alternative to MIT self-generating (id. 21). In addition, the Company argues that while MIT was contemplating various iterations of its cogeneration plans, Cambridge was required to continue to plan and operate its system, consistent with its obligation to serve MIT as a full-requirements service customer (id. at 22). Finally, the Company contends that at the first point at which MIT's intention to self-generate became real, the Company properly reflected the potential for MIT's departure in its IRM filing in D.P.U. 91-234 (id. at 24).

Addressing MIT's claim that the cogeneration project will produce benefits to Cambridge's customers, the Company argues that MIT's analysis of the benefits is erroneous and also irrelevant to the issues before the Department in this case (Company Brief at 81).[28]

Regarding the City's position that the Department abstain from the issues raised in this proceeding relating to the CTC, the Company states that abstention is neither an available nor appropriate alternative for the Department in this case (Company Reply Brief at 44). The Company argues that abstention applies where there is concurrent jurisdiction in state and federal courts (id.). In this matter, argues the Company, no other court or agency has concurrent jurisdiction (id. at 45). The Company also contends that abstention is not available because the Company's tariffs must either go into effect by operation of law or be otherwise acted upon by the Department within six months (id. at 44, citing G.L. c. 164, §94; c. 25, § 18).

B. Analysis and Findings

Cambridge argued that it should be allowed to recover prudent costs that were incurred to

[28] The Company contends that even if the economics of MIT's self-generation facilities were relevant to the issues, the MIT project does not provide net benefits to the Company's system (Company Reply Brief at 33).

serve MIT as an all-requirements customer and that its approach is consistent with the principles set out in the Department's Order in Electric Industry Restructuring, D.P.U. 95-30. MIT asserted that the imposition of the CTC is unlawful because it is inconsistent with the requirements of PURPA, is an improper tying arrangement, and is not calculated properly.[29]

The Department stated in D.P.U. 95-30, at 29, that utilities should have a reasonable opportunity to recover net, non-mitigable stranded costs associated with commitments previously incurred pursuant to their legal obligations to provide electric service. The Department's focus there was on stranded costs that may arise as the result of Department initiatives to promote competition in the generation sector of the electric utility industry by giving customers access to other sources of electricity supply in addition to the electric company in whose distribution territory these customers were located. Id. at 29, 32. The matter currently before the Department differs somewhat from the model described in D.P.U. 95-30. The Company did not file the CTC tariff as the result of D.P.U. 95-30, or any other Department initiative to promote competition in the electric utility industry. In fact, the Company's tariff filing pre-dates the Department's Order in D.P.U. 95-30. Moreover, cogeneration has been an option for many years, and has been promoted as a national policy since at least 1978 with the passage of PURPA. The record is clear that MIT has been investigating the cogeneration option since 1985, and that the Company has been aware of MIT's interest. The MIT project is representative of the business risk to which electric utilities have been exposed since at least 1978 when PURPA was enacted.

However, given the length of time over which MIT planned but did not act, the Company could well have regarded the MIT project as one of any number of plans by customers that do not

29 MIT's other legal arguments against the CTC are addressed in Section II.C, above.

go beyond the design or financing stage. In the meantime, Cambridge had to plan and procure resources to meet its obligation to serve MIT, a long-term customer of significant load. In fairness, the Company should have a reasonable opportunity to recover its investments, including those undertaken to serve MIT. See Federal Power Commission v. Hope Natural Gas, 320 U.S. 591 (1944); Bluefield Water Works & Improvement Co. v. Public Service Commission, 262 U.S. 679 (1923). Moreover, the Department is concerned about the significant impact of the loss of MIT on the Company and its ratepayers, given the relative size of MIT's load on Cambridge's system.

Thus, the Department is required to balance several competing interests. In so doing, the Department relies on its broad and widely acknowledged authority to determine such matters in the public interest. Commonwealth Electric Company v. Department of Public Utilities, 397 Mass. 361, 369 (1986); Lowell Gas Light Company v. Department of Public Utilities, 319 Mass. 46, 52 (1946); Boston v. Edison Electric Illuminating Company, 242 Mass. 305, 309 (1922).

MIT relies, in part, on PURPA to argue that the Department is without authority to approve the proposed CTC. MIT's argument seems to suggest that PURPA preempts any Department action on the proposed CTC, or certainly Department approval of a charge related to stranded investment recovery, including the CTC, so long as a QF is involved. Because the CTC would be imposed on a QF, the Department must ensure that the CTC does not offend PURPA. But the tariff in question applies to a broader class of customers, only one of which, MIT, is a QF. These customers, both individually and collectively, represent a large portion of Cambridge's load and revenues. Application of the CTC to the class as a whole, subject to the conditions expressed elsewhere in this Order, is consistent with Department ratemaking principles.

We must inquire, therefore, whether Department approval of the CTC, which would apply to a rate class member who also happens to be a QF, is a lawful exercise of ratemaking authority under PURPA. PURPA, in fact, expressly provides for state regulatory bodies to act under it, rather than be preempted by it. 16 U.S.C. § 824a-3(f)(1); FERC v. Mississippi, 456 U.S. at 751. Both PURPA and its implementing regulations employ well-understood terms of ratemaking art that have long been accorded broad construction: sales rates to QFs must be "just and reasonable and in the public interest" and non-discriminatory. 16 U.S.C. § 824a-3(c); 18 C.F.R. § 292.305(a)(1). The FERC regulations implementing PURPA also state that rates to QFs will not be deemed discriminatory if they are based on accurate data and consistent systemwide costing principles. 18 C.F.R. § 292.305(a)(2).

The CTC, as proposed by the Company, is based on consistent systemwide costing principles that apply to all large customers in the load at risk class. The CTC applies equally to all class customers, whether QF or not. The terms of service cannot reasonably be said to discriminate against QFs as such. See Boston Edison Company, D.P.U. 92-92, at 63 (1992). While the impact of the CTC would vary depending on the size of the specific customer, it would not block or unduly burden development of QFs in the Company's service territory per se. Although the Department does not endorse the Company's specific method for calculating the CTC, as discussed below, the CTC is non-discriminatory as applied to the load at risk class.

While MIT would have the Department view the instant dispute as just another example of utility resistance to small power development that PURPA sought to control, the Department finds that, for a number of reasons, this dispute presents considerations that require the Department to take a much broader public interest viewpoint. First, this matter comes to the

Department in unusual circumstances: the Department has endorsed, in principle, recovery of costs stranded due to the restructuring of the industry, because such recovery will advance the public policy interest in competition as a means to increase efficiency in electric generation and service provision. However, no method for calculation of such costs and no particular recovery mechanism have yet been approved. Further, negotiations on these issues are just beginning pursuant to D.P.U. 95-30.[30] The nationwide movement toward restructuring is by no means inconsistent with PURPA's "public interest" mandate or with PURPA's underlying goals of diversifying electric generation and reducing rates.[31] In fact, restructuring can be viewed as a direct outgrowth of the competitive forces PURPA set in motion. See D.P.U. 95-30, at 8, 13-14.

Second, where, as here, an electric utility has long been charged with an obligation to serve and has made certain investments to that end, reviewed and sanctioned by a public regulator, the problem posed by the stranding of the level of costs left by the departure of such a major customer does not yield to the simple resolution MIT urges the Department to impose. The size of MIT's load, compared to Cambridge's system and customer base, raises serious economic concerns for the Company, for the City, and for Cambridge's remaining customers. As noted above, the class of seven customers that comprises the load at risk represents 21 percent of the Company's peak load and provides 19 percent of Cambridge's total annual revenues. Nothing in PURPA suggests that a state regulator must ignore such concerns in protecting a QF's legitimate interests.[32] Indeed, the mandate to set rates which are "just and reasonable and in the

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30 In D.P.U. 95-30, at 46-47, the Department directed BECo, Massachusetts Electric Company, and WMECo to develop restructuring proposals that would include stranded cost recovery mechanisms and to begin settlement negotiations with interested parties.

31 Pub. L. No. 95-617, 92 Stat. 3119 (1978).

(continued...)

public interest" directs that the larger view be taken where warranted, as is the case here.

MIT seeks to obtain savings from an alternative generating facility while leaving the costs associated with its departure from Cambridge's system to be assumed by the Company and its ratepayers. MIT also seeks to remain a customer, albeit at less than an all- requirements basis. The Department regards allowance of a carefully designed and time-limited mechanism that balances the interests of MIT, the Company, and its remaining full-service ratepayers as consistent with PURPA's "public interest" standard.

However, the Company's method of determining stranded costs is not supported by precedent, as this is an issue of first impression. In D.P.U. 95-30, at 46-47, the Department did not endorse any specific methods for calculating stranded costs; rather we anticipated proposals for such methods evolving from negotiations among all appropriate representatives.[33]

The Attorney General and MIT argue that Cambridge knew MIT was planning to leave its system and that Cambridge did not take sufficient actions to mitigate the loss of MIT (Attorney

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[32] (...continued)
In fact, the opposite conclusion can be drawn from the PURPA regulation which allows a state regulatory body to waive the requirement that an electric utility provide standby/supplemental service to a QF, where such an arrangement would be unduly burdensome or adverse to overall customer service. 18 C.F.R. § 292.305(b)(2). Where a state regulatory body can, in the public interest, altogether waive the requirements of such service, that body a fortiori ought to be able, also in the public interest, to approve reasonable conditions to providing standby/supplemental service. In essence, Cambridge urges us to do just that.

[33] Specifically, the Department set out a schedule for companies to submit restructuring proposals, which incorporate unbundled rates for all customers and include a non-bypassable mechanism that provides a reasonable opportunity to recover net, non-mitigable stranded costs; Cambridge's filing is to be submitted three months after the issuance of the Department's Orders on BECo, Massachusetts Electric Company, and WMECo. D.P.U. 95-30, at 29, 47-48.

General Brief at 6; MIT Reply Brief at 8). The earliest evidence that the Company anticipated the loss of MIT as an all-requirements customer in its contingency planning is in its 1991 IRM proceeding. D.P.U. 91-234, at 121. Although it is not beyond dispute that Cambridge did all it could to mitigate the loss of MIT in a timely way, we recognize that throughout the period when MIT was refining its self-generation planning, the Company also had an obligation to serve both all-requirements and partial-requirements customers. While MIT assessed the future course most advantageous to it, Cambridge had to obtain resources available to serve all its customers. MIT was just such a customer, and given the narrow reserve capacity margins that existed in the late 1980's, the Company might well have been criticized had it proposed to treat MIT's plans since 1985 as absolving it of its obligation to serve that load.

MIT also argues that the Company did not negotiate in good faith. To the contrary, there is evidence that the Company pursued many avenues to avoid losing MIT as a customer (Exh. MIT-13 Supp.; Tr. 1, at 44). In general, Cambridge offered several deferral options to MIT that the Company characterized as making MIT indifferent between cogenerating and remaining an all-requirements customer on the Company's system (Exh. MIT-13 Supp.). Although the Company's efforts were unsuccessful, they were not insubstantial. While questions have been raised about whether Cambridge should have anticipated MIT's departure sooner and whether it should have acted earlier and more aggressively to reduce the impact on ratepayers of such an event, the Department finds no clear evidence of imprudence on Cambridge's part. The record does not permit us to conclude that Cambridge did not act in good faith in its negotiations to avoid losing MIT as a customer.

In addition, MIT criticizes several aspects of the Company's calculation of the CTC. The

Department also has concerns about the method of calculating the CTC. The charge begins with a "load at risk" class that comprises the Company's seven largest customers, including MIT. The record shows that the Company, however, is not aware of any present plans by other customers to self-generate or otherwise abandon full-service status (Tr. 1, at 28). One of the customers, Harvard University, recently signed a seven-year contract to remain on the Company's Rate G-3 (Tr. 1, at 33). Therefore, the Department regards the risk to Cambridge of all these customers' departing Cambridge's system as overstated, though not enough to invalidate the class as conceived. The Department further finds that the Company's elimination of variable energy costs in order to determine gross stranded costs and its reduction of such gross stranded costs by the three mitigation factors to obtain a net stranded costs figure involve assumptions by the Company that introduce a margin of error into the Company's calculation. Continued service revenue, market value, and load growth mitigation are all difficult to project accurately. Unfortunately, these uncertainties cannot be precisely quantified in order to adjust the CTC. Moreover, the Department regards the quantification of these uncertainties as impractical at this time of transition toward restructuring. However, these uncertainties are not so significant as to render the CTC as designed inadequate for ratemaking purposes.

Given the considerations discussed above, the Department finds that it is appropriate to balance the interests of the load at risk class and the interests of Cambridge and its other ratepayers by apportioning the stranded costs claimed by the Company.[34] Therefore, after

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[34] In the past, in a somewhat different context, when confronted with a significant loss to a company, the Department has balanced the affected interests and apportioned the costs among them. Boston Edison Company, D.P.U. 906, at 242 (1982). In that case, the Department explained why it was appropriate to apportion the cancellation costs of the (continued...)

balancing the (1) Company's interests in recovering prudently incurred costs, (2) ratepayers' interests given the economic impact associated with the departure of a large customer of the Company, (3) load at risk class members' (including MIT) interests in obtaining lower cost power, and (4) public policy interests in encouraging competition as a means to increase efficiency, the Department determines that a CTC of 75 percent of the net stranded costs as calculated by Cambridge (or $5.62 per kVa) is just and reasonable under the unique circumstances of this case. The Department further finds that this apportionment of the costs of a member of the load at risk class leaving the Cambridge system as a full-service customer is in the broad public interest. The Department further finds that this apportionment does not discriminate against MIT because it

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(...continued)

Pilgrim II nuclear power plant:

> Because of the unusual magnitude of the Pilgrim II abandonment costs, our concern with the classic rate-setting dilemma of balancing the burdens is necessarily increased. We refer specifically to the consumer's burden, which arises from the rate increase necessary to compensate the Company for money prudently invested on its customers' behalf, as well as the Company's burden, which results from the necessity of a speedy financial recovery in order to ensure that the level of service demanded by its consumers is provided. Under current economic conditions, both groups are faced with continually rising prices and the resulting erosion of earnings. To ignore this fact would be irresponsible. Our goal is to select an amortization methodology which is equitable to both parties. Id. at 242-243.

In upholding the Department's Order on appeal, the Supreme Judicial Court concluded that the allocation of the these costs was within the Department's discretion. Attorney General v. Department of Public Utilities, 390 Mass. 208, 231 (1983).

Similarly, the Department determined that a "sharing of cancellation costs" for the Montague nuclear power plant was appropriate in Western Massachusetts Electric Company, D.P.U. 558, at 40 (1981).

would apply to each member of the load at risk class. In summary, the Department finds that the reduced CTC is just and reasonable, non-discriminatory, and in the public interest in accordance with G.L. c. 164, § 94, and with PURPA. Accordingly, the CTC shall be $5.62 per kVa per month.

The Department approves the reduced CTC without establishing a precedent regarding the appropriate method for calculating such costs in future proceedings. The Department hereby notes that the mechanism for recovery of stranded costs should be addressed in the negotiations on each company's Comprehensive restructuring proposal. D.P.U. 95-30, at 47. The entire question of stranded cost recovery will be systematically reviewed on both an industry-wide and a company-by-company basis with the filing of the Massachusetts Electric Company, BECo, and WMECo restructuring proposals on February 16, 1995 and again when Cambridge files its own restructuring proposal. Cambridge, however, is not due to file its own restructuring proposal until three months after the resolution of the first three companies' plans for restructuring. The current case demonstrates that Cambridge is already facing the implications of potential loss of load for its shareholders, remaining ratepayers, and potentially departing customers, even if such loss is not due directly to industry restructuring. The Department recognizes this fact in approving the reduced CTC. However, given the uncertainties associated with the CTC and its development for the purposes of a narrow load at risk class, the Department finds that the application of the CTC, revised and reduced in accordance with the present Order, shall be for a limited time period only. Therefore, the Department will accelerate the date for filing of Cambridge's and Commonwealth's comprehensive restructuring proposal(s) in accordance with D.P.U. 95-30 to August 16, 1996. Of course, G.L. c. 164, § 93 affords a mechanism to petition the Department for review of the CTC whenever market conditions or the Company's actions warrant an adjustment of the CTC.

As an additional point, MIT argues that the reference customer demand may elicit unusual outcomes in potential customers' billing.[35] The Company should not assess a charge on the entire size of the customer if it is losing only a portion of the customer's load. Such customers should pay the CTC for their actual load minus the supplemental service they require, or in MIT's example, 1,000 kVa. Therefore, the Company shall revise the definition of Customer Reference Demand to reflect this change.

MIT also maintains that the CTC is an improper tying arrangement and thus in violation of antitrust law. We do not agree. In order to establish a tying arrangement, as stated in Section II.C.5., above, MIT must prove that: (1) standby/supplemental service and the CTC are two distinct products; (2) the Company has used market power in the tying market to force MIT to accept the arrangement; and (3) the arrangement affects a substantial volume of commerce in the tied market. See Jefferson Parish Hospital District No.2 et al. v. Hyde, 466 U.S. 2, 8 (1984).

First, the determination of whether one or two products or services are involved lies with the character of the demand of the two items. Id. While the two types of rates at issue, stranded cost rates and standby/supplemental service rates, are both based on embedded costs, it is clear that two distinguishable service[36] rates are involved, one for the investment made to provide full-

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35 In MIT's example, a 3,000 kVa customer who installs a 1,000 kVa generator and pays for 2,000 kVa of supplemental service, but purchases no standby service, would pay 3,000 kVa times the CTC rate.

36 The Department notes but does not need to resolve the question of whether generation should be viewed in this instance as the sale of electrons, and therefore a product, or in the manner in which the electrons are used, and therefore a service, or whether

requirements service and one for the cost to provide standby/supplemental service. A consumer of standby/supplemental service would not also be a consumer of full-requirements service, and vice versa. Accordingly, the Department finds that two distinct services are involved in the proposed arrangement.

Next, MIT must establish that the Company has appreciable economic power in the tying market, i.e., the standby/supplemental service market, to force MIT to accept the arrangement. Market power has been defined as the ability to raise prices above the levels that would be charged in a competitive market. NCAA v. Board of Regents, 468 U.S. 85, at 109, n.38 (1984). Although the standby/supplemental service market is not yet a fully competitive market, the Company, a regulated monopoly, does not possess the ability to arbitrarily raise prices for standby/supplemental service. The Company is restricted by the requirements of G.L. c. 164, § 94, as well as the requirements of PURPA to provide standby/supplemental service at "non-discriminatory rates" that are "just and reasonable and in the public interest." 16 U.S.C. § 824a-3. Inasmuch as the Company does not have market power in the tying market, the Department determines that the proposed CTC is not a tying arrangement.

Moreover, the Department is not persuaded that the market for sale of electricity is as yet sufficiently competitive to warrant invoking the antitrust principles. Rates for the retail sale of electricity are not market-based but are, for now at least, completely regulated and determined through extensive adjudication. Thus, the concepts of market power and forced sales, as occur in

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generation is really to some degree both product and service. G.E. Lothrup Theatres v. Edison Electric Illuminating Company of Boston, 290 Mass. 189, 193 (1935). ("There may be cases where electricity will be considered a commodity subject to sale and delivery rather than a service furnished by the generating company").

tying arrangements, may have limited application at least until the transition to the model of full competition which we envision as having far less regulation of the ratemaking functions.[37]

Nonetheless, even if the Department were to find that a tying arrangement existed, the Company's proposed tariffs would be immunized from the federal and state antitrust liability under the State Action Doctrine. See Parker v. Brown, 317 U.S. 341 (1943). To enjoy such immunity, one must establish that "[f]irst, the challenged restraint must be one clearly articulated and affirmatively expressed as state policy; second, the policy must be actively supervised by the State itself." Federal Trade Commission v. Ticor Title Insurance Company et al., 504 U.S. 621, 631 (1992), citing California Retail Liquor Dealers Association v. Midcal Aluminum, Inc., 445 U.S. 97, at 105 (1980).

The Commonwealth of Massachusetts has just such a clearly articulated and affirmatively expressed policy with respect to the regulation of electric utilities' rate structures. Such a policy is found in G.L. c. 164, §§ 76, 94, 94A, 94G, and the policies which the Department has issued pursuant thereto. See Boston Gas Company, D.P.U. 93-60 (1993); Cambridge Electric Light Company, D.P.U. 92-250 (1993); Monsanto Company v. Department of Public Utilities, 412 Mass. 25, 28 (1992). Moreover, the Department has expressed clearly its policy with respect to allowing utilities "a reasonable opportunity to recover costs for existing commitments that might be stranded in the transition to competition." D.P.U. 95-30, at 33. The instant Order is a further articulation of the Commonwealth's regulatory policy.

Furthermore, these policies are actively supervised by the Department; the intense and

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[37] In another context, the Court has cautioned against reliance on analogies to other areas of law "to define a utility's responsibility" in the regulated area of rates. Commonwealth Electric Company v. Department of Public Utilities, 397 Mass. 361, 367 (1986).

protracted investigation in D.P.U. 94-101/95-36 itself exemplifies the degree to which the Department supervises the regulation of utility rate structures and stranded costs. The CTC cannot be imposed without Department approval. And, in expressing that approval in this Order, the Department has directed certain modifications in the CTC as originally proposed by the Company. In addition, the Department has established a schedule by which it will actively review utility proposals for the recovery of stranded costs. Id. at 47. Accordingly, the Department finds that even if it were to conclude that a tying arrangement existed, comprehensive supervision of the CTC in the electric restructuring effort would, under the State Action doctrine, immunize the proposed tariff from antitrust scrutiny.

VII. ORDER

Accordingly, after due notice, hearing, and consideration, it is

ORDERED: That the tariff, M.D.P.U. No. 553, filed with the Department on March 15, 1995, be and hereby is ALLOWED; and it is

FURTHER ORDERED: That the tariffs, M.D.P.U. Nos. 551, 552, and 554, filed with the Department on March 15, 1995, be and hereby are DISALLOWED; and it is

FURTHER ORDERED: That Cambridge Electric Light Company shall file new tariffs in accordance with the directives contained in this Order; and it is

FURTHER ORDERED: That the new tariffs shall apply on or after the date of the Order, but shall not become effective earlier than seven (7) days after they are filed with supporting data demonstrating that such rates comply with this Order.

By Order of the Department,

Kenneth Gordon, Chairman

Mary Clark Webster, Commissioner

CONCURRENCE OF COMMISSIONER BESSER

The Department faces a difficult and delicate task in balancing the competing interests that come before us in the instant docket with respect to Cambridge's proposed CTC tariff. These include (1) the Company's interest in recovering costs that were prudently incurred to serve its customers; (2) ratepayers' interests given the economic impact associated with the departure of a large portion of the load of the Company; (3) the departing customer's (or customers') interest in obtaining lower cost power and ability to do so; and (4) public policy interests in encouraging competition as a means to increase efficiency in and thereby reduce costs for provision of electric service.

The Department's Order clearly lays out the considerations surrounding this decision. It notes that in our Order on electric industry restructuring, the Department reached the conclusion that public policy interests demand that utilities should have a reasonable opportunity to recover net, non-mitigable stranded costs associated with commitments previously incurred pursuant to their legal obligations to provide electric service. D.P.U. 95-30, at 29. The Department's focus in D.P.U. 95-30 was on stranded costs that may arise as the result of Department initiatives to promote competition in the generation sector of the electric utility industry by giving customers the opportunity to choose alternative suppliers.

However, the Order also notes that the matter currently before us differs from the situation described in D.P.U. 95-30. The Company's CTC tariff filing pre-dates the Department's Order in D.P.U. 95-30; cogeneration and self-generation, such as that proposed by MIT, have been options for customers for many years; and cogeneration has been promoted as a national policy since PURPA in 1978. Consequently, the MIT project can be viewed as representative of the business risk to which utilities have been exposed for some time.

The loss of a customer to cogeneration or self-generation may be a business risk that utilities should anticipate. However, the loss of a single customer the size of MIT relative to the Cambridge system may lead to cost impacts for remaining ratepayers that are unacceptable. Under traditional ratemaking practices, if the Company's actions were found to be prudent, remaining ratepayers would bear the consequences at the time of the next rate case. Boston Gas Company, D.P.U. 93-60, at 24 (1993). In the case of MIT and Cambridge, the Company estimates that this could result in an average rate increase of over 6% (Exh. RDW-1, at 20). Loss of the load at risk class as a whole could result in an increase of 14%. This would not be in the public interest.

At the same time, an individual customer whose electricity and energy service needs are such that cogeneration or self-generation is an attractive alternative to continued utility service should be able to make that choice.[38] In fact, the ability of customers to choose alternatives to their traditional utility suppliers will provide the incentive to utilities to reduce costs and improve services, thereby benefiting all customers. A customer's ability to choose alternatives to its traditional utility supplier will be affected by the cost of leaving the utility. If the departing customer is asked to bear a disproportionate share of costs the utility claims to have incurred to

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[38] If the cogenerating or self-generating customer wishes to receive back-up, standby and/or maintenance services from the distribution utility, that customer should expect to pay just and reasonable rates for those services. I concur with the Department's Order on Cambridge's back-up, standby and maintenance tariffs and note that these tariffs are designed to cover all of the Company's costs for providing these services.

serve him, he may not be able to exercise his choice effectively.

Moreover, there is a public policy interest in promoting competition in electric generation markets. The Department's Order on restructuring spoke to this interest in great detail. See, e.g., D.P.U. 95-30, at 13. There, the Department found that customer choice is the guarantor of efficient and fully competitive markets. D.P.U. 95-30, at 15. Increased efficiency will bring long term benefits, in the form of lower costs and improved services, to all electricity consumers.

The balancing of the interests discussed above argues for a sharing of stranded costs among the Company, its ratepayers and departing customers, in this case the load at risk class. The Order recognized this in determining that a CTC of 75 percent of net stranded costs as calculated by Cambridge is just and reasonable under the unique circumstances of this case. The Order further limits the imposition of the CTC to the period of time until Cambridge files its comprehensive restructuring plan, now due August 16, 1996.[39]

I concur with the rationale underlying the Department's Order. However, I believe that a more appropriate balancing of the interests under these circumstances warrants a more equitable sharing of the stranded costs, e.g., 60% of the CTC charged to MIT and 40% remaining with the Company and its ratepayers. Moreover, I think that the Department Order itself argues for a more equitable split. I am concerned that the imposition of 75% of the CTC charge on MIT will undermine the development of the competitive generation market that will ultimately produce benefits for all customers.

I agree that the Department's Order does not establish precedent for determination of the

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[39] I concur with the decision to require the filing of Cambridge's comprehensive restructuring proposal by August 16, 1996.

level of stranded costs, the allocation of such costs, or the appropriate mechanism for recovery of such costs. I reaffirm the view in D.P.U. 95-30, that negotiations among the affected parties, consistent with the Department's principles as outlined therein, offer the soundest foundation for moving forward in a timely manner with the restructuring of the electric industry. A determination of what will constitute an equitable sharing of the burdens of stranded costs may be best made by the parties who will have to bear these costs.

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Janet Gail Besser, Commissioner